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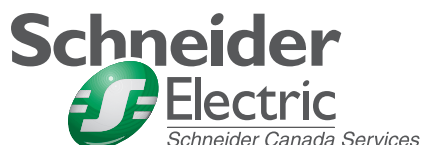
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CIRCUIT BREAKERS & SWITCHGEAR HANDBOOK VOLUME 2

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The Electricity Forum
A Division of the Hurst Communications Group Inc.
All rights reserved. No part of this book may be reproduced without
the written permission of the publisher.
ISBN-0-9738854-8-3
The Electricity Forum
215 - 1885 Clements Road, Pickering, ON L1W 3V4

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SPECIFICATIONS AND STANDARDS FOR CIRCUIT BREAKERS AND SUPPLEMENTARY PROTECTORS

Courtesy of E-T-A Circuit Breakers

Electrical engineers do not want to see designs go up in smoke. Naturally, engineers protect their equipment with what they believe to be appropriate circuit protection. However, there is widespread misunderstanding of industry standards for circuit protection and the meaning of terms such as “circuit breakers”, “supplementary protectors”, “circuit breakers for equipment” and “branch circuit protection”. In some cases, this confusion results in the specification of the wrong type of circuit protection and increases the risk of overheating, premature failure and catastrophic faults.

To understand the source of the confusion and to learn how to specify circuit protection correctly, we need to review standards and how they are applied.

BRANCH CIRCUIT PROTECTION

The National Electrical Code (NEC) is primarily concerned with the safety of hard-wired branch circuits within a building. Article 100 defines a branch circuit as “the circuit conductors between the final overcurrent device protecting the circuit and the outlet.”

For overcurrent protection devices in a branch circuit, the requirements are spelled out in a standard called UL 489, “Standard for Molded-Case Circuit Breakers and Circuit Breaker Enclosures”, published by Underwriters Laboratories, Inc.

UL 489

UL 489 encompasses circuit breakers “intended for installation in a circuit breaker enclosure or as parts of other devices, such as service entrance equipment and panelboards”. According to UL terminology, devices meeting this standard are considered listed products.

For approval, UL 489 requires the device pass a series of calibration, overload, endurance and short-circuit tests. (See Figure 1.) The minimum short-circuit test must be performed at 5000A. Overload tests are performed at six times the current rating of the device or 150A minimum. Devices rated up to 600V and 6,000A are covered in this standard. Additionally, most UL 489 devices are used in electrical distribution panels; therefore, the minimum current ratings available are seldom less than 15A. During UL 489 testing, the device must survive short-circuit testing and continue to provide future overload protection.

In service entrance panels, available short-circuit fault currents measure 50,000A or greater. However, as power is distributed throughout a building, the available short-circuit currents diminish. If an electrical outlet is just 20 feet away from the power source, Ohm’s law states even with limitless available short-circuit current AWG 14 copper wire limits the maximum available fault current at the outlet to no more than 1200A at 120V.

Supplementary Protection

Although the NEC recognizes “supplementary overcurrent protection used for lighting fixtures, appliances and other equipment or for internal circuits and components of equipment”, it does not specifically define supplementary overcurrent protection. Nonetheless, the NEC implies that it is used in conjunction (in series) with a branch circuit overcurrent device upstream of the equipment. The requirements of supplementary protectors are described in UL 1077, “Standard for Supplementary Protectors for Use in Electrical Equipment”.

UL 1077

UL 1077 defines supplementary protectors as devices intended for use as overcurrent, over-voltage or under-voltage protection within an appliance or other electrical equipment where branch circuit overcurrent protection is already provided or is not required. In UL terms, UL 1077 compliant devices are labeled as recognized components.

Similar to UL 489, UL 1077 supplementary protectors must pass a series of calibration, overload, endurance and short-circuit tests. (See Figure 1.)

Because most UL 1077 circuit breakers are rated 20A or less and are used in electrical appliances or other types of utilization equipment, the overload and short-circuit tests are generally performed at lower levels than those required by UL 489. To pass the short-circuit test under UL 1077, the device must safely interrupt short-circuits at least one time without causing a fire hazard. Unlike UL 489, it does not necessarily need to survive the test. In 1999, UL introduced a new category to UL 1077 that includes survivability and recalibration approvals.

NOT ALL UL 1077 SUPPLEMENTARY PROTECTORS ARE ALIKE

UL 1077 allows manufacturers to obtain approval for different circuit conditions. For example, an overcurrent supplementary protector can be short-circuit tested with or without a backup fuse or circuit breaker. A supplementary protector can be overload tested at 1.5 times its rating for general use or 6 times its rating for across-the-line motor starting. It may trip at less than 125 percent of its rating or greater than 135 percent, etc.

“FIT FOR FURTHER USE”

When UL 1077 was revised to meet changing market requirements and safety considerations, UL added a category of overcurrent supplementary protectors known as “recalibrated after short-circuit testing” which are also described as “fit for further use”.

Overcurrent supplementary protectors rated “fit for further use” survive a three cycle short-circuit test and continue to

provide overload and short-circuit protection in future operations. Not all manufacturers of UL 1077 approved circuit breakers strive to meet this more stringent classification. Before selecting a manufacturer, it is essential for the design engineer to verify which tests the circuit breakers are subjected to. If the data sheet provided by the manufacturer does not provide this information, the UL Recognized Component Directory for Supplementary Protectors can be used as a reference in determining the suitability of the protectors as “fit for further use” and/or for motor starting applications, etc.

Below is an example of the UL Recognized Component Directory for Supplementary Protectors. Included is a definition of each code pertaining to the supplementary protector.

It is the duty of the design engineer to select the proper supplementary protector for the application to ensure optimal safety and reliability.

Catalog #	412 (G)	
Type	OC	An overcurrent type protector
UG	B, D	Intended for commercial or household appliances
FW	0	Terminals fixed from factory
Max V	28 DC	Maximum voltage either AC or DC
Max Amps	0.1 - 35	Range of current ratings
TC	2	Tripping current more than 135%
OL	0	Overload test performed at 150%
SC	6 KA, U, 2	Short-circuit test performed at 6,000A without series overcurrent protection, recalibration test performed after short-circuit, “fit for further use”

UL Recognized Component Directory for Supplementary Protectors

A Brief Comparison of UL 489 and UL 1077 Test Standards and Requirements is shown on the following page.

Most supplementary protectors are used in electrical or electronic equipment that is plugged into an outlet. The outlet is wired to a UL 489 listed circuit breaker in an electrical distribution panelboard. Since the distance between the panelboard and the outlet can easily be 50 feet or more, the resistance of 50 feet of AWG 12 or 14 wiring reduces the available short-circuit current at the outlet to well under 1000A.

When the continuous current rating of equipment exceeds 20A and is hard wired to the electrical distribution panelboard, or has a convenience outlet for service and test equipment, the meanings of branch circuit and branch circuit protection become blurred.

Prior to the publication of the “fit for further use” standard, inspectors were uncertain if the supplementary protectors in industrial and commercial equipment would adequately protect certain loads after short-circuit faults. As a result, some

local governing authorities began to require branch circuit protection within utilization equipment. Because the term branch circuit protection is interpreted as requiring a UL listed device, UL 489 circuit breakers are being used in equipment that would be better protected by “fit for further use” rated UL 1077 supplementary protectors.

In order to meet the requirement for branch circuit protection as well as for economic and convenience reasons, a manufacturer may replace an 8A supplementary protector circuit breaker with a 15A listed circuit breaker. The manufacturer meets requirements and may gain additional short-circuit protection; however, overload protection is lost. If the circuit is a motor load or other type of load where overloads often occur, conditions such as a locked rotor may go unnoticed and unprotected causing motor failure or, worse yet, overheating of wire insulation, fires and catastrophic short-circuits.

In contrast, a “fit for further use” UL 1077 supplementary protector will protect the equipment during short-circuits and during common overloads.

UL 489A

In the same way the “fit for further use” classification was created to address real world applications, UL 489A is an outline of investigation established in response to the needs of communications equipment. Communications equipment, such as a telecommunication base station, uses DC rather than AC power. Low voltage DC fault currents are far more sensitive to resistance than AC currents. In most telecommunications applications, a circuit breaker with 2000A interrupting capacity is more than adequate, yet UL 489 requires a minimum interrupting capacity of 5000A. UL 489A addresses this concern by allowing such ratings to be determined by the user and device manufacturer.

CONCLUSION

As electrical and electronic equipment increases in complexity, it is necessary to protect the operator from the effects of equipment failure and protect the equipment from costly damage and downtime. With a clear understanding of UL standards and requirements, the design engineer is assured optimal performance and safety.

UL 1077 supplementary protector circuit breakers are available from E-T-A in current ratings from 0.05A to 500A and in voltage ratings up to 600V. Several E-T-A UL 1077 circuit breakers are now approved as “fit for further use” and are available in a variety of current ratings. In addition to adequate short-circuit protection, these circuit breakers are sized for precise, continuous current levels protecting equipment from premature failure due to overloads.

	UL 1077	UL 489
MINIMUM TERMINAL SPACING	For commercial appliances 3/32 inch up to 300 V 1/4 inch at terminals	1/2 inch up to 130 V 3/4 inch up to 300 V 1 inch up to 600 V through air
CALIBRATION TEST	@ 300% and @ trip current +5%	varies with current rating 12 seconds to 2 minutes @ 200%, <1 hour @135% (<50A), <2 hours @ 135% (>50A)
MAXIMUM TEMPERATURE RISE AT TERMINAL	50°C / 122°F	50°C / 122°F
OVERLOAD TEST	50 cycles @ 1.5 x I_N (general use) @ 6 x I_N (across-the-line motor starting)	50 cycles @ 6 x I_N or 150 A minimum
ENDURANCE TEST	6,000 cycles @ I_N (S-type only)	10,000 cycles (6,000 @ I_N + 4,000 mechanical (up to 100A)
SHORT-CIRCUIT TEST	1-3 times (C-0-0) at 5,000A or less, depends on current and voltage (may fail safe or recalibrate after short-circuit tests for "fit for further use")	Depends on ratings. 3-7 times @ 5000A minimum + must operate @ 200% final test

Figure 1

A NOVEL CONTINUOUS ON-LINE PD MONITOR FOR MOTORS, SWITCHGEAR AND DRY-TYPE TRANSFORMERS

By Mark Fenger, Greg C. Stone, Iris Power Engineering

ABSTRACT

Partial Discharge (PD) monitoring is a recognized testing method for identification of deterioration of stator winding insulation of high voltage rotating machines such as hydraulic generators, high-speed turbine generators and large motors. Partial Discharge monitoring of machine stator windings detects most of the common failure mechanisms, such as overheating, contamination and loose windings. PD monitoring complements other on-line monitors that are currently available for machines and electrical equipment such as, for instance, vibration monitors and temperature monitors. Although less applied, PD monitoring can also detect incipient failure of dry-type transformers and switchgear components.

Based on a proven technology, new devices have been developed for continuous on-line monitoring of motor stator windings, switchgear components as well as dry-type transformers. Using sophisticated triggering algorithms based on operating conditions, the device monitors and trends PD activity and stores data for further analysis. As well, the devices contain advanced algorithms for providing reliable alarms indicative of insulation aging based on the PD activity measured. Depending on the application, the devices provide months, to years, of advanced warning of severe insulation deterioration and allow plant personnel to plan for corrective action. The on-line PD monitors are effective tools for implementation of condition-based maintenance (CBM) on medium voltage motors without requiring outages for routine testing and inspections.

INTRODUCTION

In the past decade, a large number of utility and industrial plants have adapted condition-based maintenance (CBM) programs (also known as predictive maintenance programs) for major equipment. Specifically, CBM allows plant maintenance personnel to avoid unexpected in-service failures by identifying which motors require outages for further testing and/or repair. CBM programs thus help prevent expensive and unnecessary equipment shutdowns for either testing or repairs. The impact of this is twofold: CBM allows for the continuous accumulation of specific knowledge on maintenance of machines and, furthermore, CBM allows for economical optimization of maintenance and repair budgets. In fact, the overall savings resulting from implementation of CBM is, most often, significant. Specifically, CBM increases the availability of electrical equipment while decreasing the overall maintenance costs.

Directing maintenance efforts towards electrical equipment most in need of attention requires implementation of reliable CBM programs which, again, requires use of diagnostic

monitoring methods allowing for reliable detection of problems. For economical and technical reasons, diagnostic monitoring performed during normal on-line operation (as opposed to monitoring performed during off-line conditions) is, without question, preferable. This is partly due to the fact that equipment outages are often expensive and/or time consuming and, furthermore, partly due to the fact that some failure mechanisms may only be detected during normal operational conditions.

Condition-Based Monitoring can be applied to various electrical and mechanical components but, in the following, the focus will be on CBM for motors operating in utility and industrial plants. As documented in various publications, for motor and generator applications, sophisticated on-line monitors have been developed over the past 15 years. Efforts have been invested in developing new or refining existing technologies so as to be sensitive to motor problems related to bearings and the rotor winding. Application of vibration monitoring, airgap flux monitoring and current signature analysis have been proven to be successful with regards to detection of bearing and rotor problems in rotating machines well before a catastrophic failure would have occurred - often at a fraction of the total cost involved with an actual failure.

However, bearings and rotors are only two of the main components of a motor. In a survey of over 7500 motor failures, 37% of significant forced outages were actually caused by the third major component: stator windings [1].

On-line Partial Discharge testing is a recognized test method for detection of stator winding insulation problems [1-4, 10-12]. Although periodic on-line tests are frequently used to monitor the health of the winding insulation for high voltage stators, continuous on-line monitoring of medium voltage motor windings (rated up to 6.6 kV) has, traditionally, been less frequently used. However, in the past seven years, various utility and industrial plants have adapted a new technology, MotorTrac, which helps assess the general health of the stator winding of a medium voltage motor using continuous on-line monitoring techniques and thus helps to further strengthen Condition-Based Monitoring of motors. In many cases, the implementation of this technology has helped to prevent stator failures. Similar arguments can be made for the case of switchgear components as well as dry-type transformers.

Based on the past seven years of experience with MotorTrac technology, a new device, PDTrac, for continuous on-line stator-winding monitor for motors, switchgear and dry-type transformers has been developed. PDTrac constitutes the first instrument in a new generation of continuous on-line PD monitors using complex operation condition-based data acquisition algorithms which result in very reliable insulation aging

trends, and consequently, very reliable alarms.

Focusing on monitoring of stator windings, this paper describes the functionality of the new, improved on-line PD monitor based on seven years of accumulated experience of continuous on-line stator winding monitors.

PARTIAL DISCHARGE PHENOMENA IN ELECTRICAL EQUIPMENT

A Partial Discharge (PD) is an incomplete, or partial electrical discharge that occurs between insulation and either insulation or a conductor. It is well known that the presence of voids internal to electrical insulation may lead to the presence of partial discharges if the electrical field distribution internal to the void is of sufficient strength and an initiatory electron exists. Contaminants on insulation surfaces may also result in partial discharge activity due to enhancement of the local electric field. A PD internal to the insulation or along the insulation surface will initially give rise to a high frequency current, traveling along the conductor, which is detectable by electrical sensors.

A description of PD theory is well beyond the scope of this paper, but partly relates to material science and partly to electrical field theory. With respect to the latter, it can be shown that the electrical field distribution within the bulk dielectric determines PD behaviour as manifested in phase resolved patterns [15, 16].

Following a macroscopic electrical field theoretical approach for PD in voids internal to the insulation, Pedersen, McAllister and Crichton have shown that the proximity of the void or discharge location to the measuring electrode has a significant effect on the magnitude of the induced image charge on the measuring electrode [15, 17]. The model therefore shows that a quantitative analysis of PD data must rely on a trend of the PD activity rather than an analysis of individual PD magnitudes [15]. A trend of PD activity over time thus shows the progression of the various aging mechanisms acting on an insulation system.

PD AS A SYMPTOM OF STATOR WINDING INSULATION AGING

Modern stator winding insulation consists predominantly of two components: mica paper impregnated with epoxy or polyester. Although the organic epoxy and polyester resins are easily degraded by partial discharges, the crystalline mica is essentially impervious to moderate levels of PD.

Given mica's resistance to PD, most stator windings failures are therefore a result of long-term aging [7]. The presence of partial discharges in stator winding insulation is, in most cases, thus not directly causing insulation deterioration but rather a symptom of insulation deterioration caused by aging stresses.

Four aging stresses act on stator winding insulation during normal operation: chemical, thermal, mechanical and electrical stresses. In published literature, environmental stresses may often be mentioned as a fifth aging stress. For smaller high voltage motors (2 kV – 6 kV), thermal and environment stresses are the two most predominant causes of stator winding failures. For larger HV motors, 6kV and above, mechanical and thermal stresses constitute the two most predominant causes of stator winding failure.

There are a few failure mechanisms occurring in stator windings in which PD is the predominant cause of deterioration. These include PD occurring in large voids next to the copper

conductors, caused by poor impregnation of epoxy or polyester during manufacturing or by loss of bonding due to thermal cycling during normal machine operation. For multi turn coils, PD occurring in these voids, if large enough, may gradually penetrate layers of mica paper tape insulation eventually leading to a turn insulation fault [6]. Similarly, electrical tracking may occur along polluted endwinding surfaces eventually causing a phase-to-phase or phase-to-ground failure.

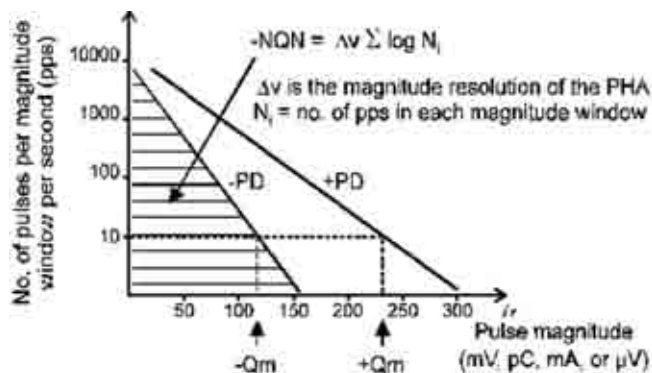


Figure 1: PD Summary Numbers

PD DATA INTERPRETATION

As stated earlier, PD is a symptom of insulation aging. The number of voids internal to the stator winding insulation increases as the insulation ages. Thus, so does the number of partial discharges. As the size of the individual void increases, so does the magnitude of partial discharges.

Time based trending of two summary numbers, NQN and Qm, expresses increases in number of voids (discharge locations) and void size. NQN and Qm are derived from a two-dimensional PD plot – see Figure 1- in which PD pulse count rate is expressed as a function of PD magnitude. NQN is defined as the area underneath the curve and thus relates to the relative number of voids in which PD occurs. Qm is defined as the magnitude of PD pulses having a repetition rate of 10 pulses per second and thus relates to the size of the largest voids internal to the insulation [11,12,14-17].

As insulation aging mechanisms starts to progress rapidly, NQN and Qm will increase as sketched in Figure 2. Thus,

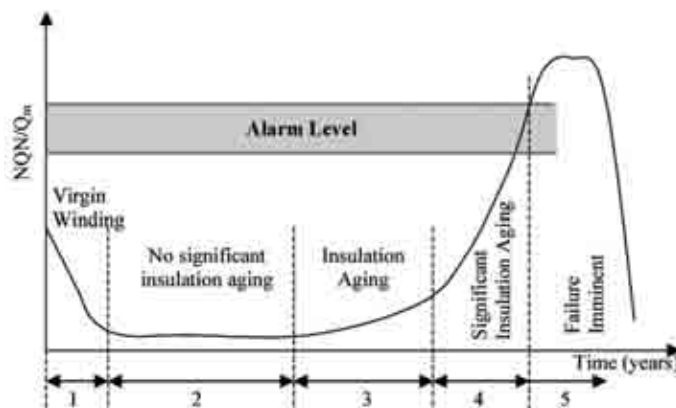


Figure 2: Sketch of Typical Trend Curve

when NQN and/or Q_m increase exponentially, the operator of the machine should plan for possibly further testing and/or possibly corrective maintenance.

Although quantitative interpretation of PD data acquired from one machine must rely on trending of the PD activity measured over time [5,8,11,12], and at similar operating conditions, comparing a set of data obtained on one machine with the cumulative probability function of PD magnitudes derived from a very large population of PD tests acquired on similar machines, (i.e. similar in insulation material and voltage ratings using similar test equipment) does contain information on the state of the stator winding [12]. The 90% percentile PD magnitudes may be used as a reference for an alarm level.

Voltage Rating	PD Summary Number – Q_m [mV]				
	2-4 kV	6-8 kV	10-12 kV	13-15 kV	16- 18 kV
Avg.	182	137	287	310	515
Max.	3200	1626	3079	3200	3200
25%	6	12	34	36	36
50%	40	35	77	95	72
75%	136	143	188	220	260
90%	262	267	414	477	2090

Table 1: Cumulative Q_m distribution for air-cooled machines of different voltage classes

Finally, it should be mentioned that by measuring the phase angle at which a PD pulse occurs, a phase resolved PD plot may be created. This allows for a Pulse Phase Analysis [12-14] and the identification of specific motor winding insulation problems.

PARAMETERS AFFECTING PD SUMMARY NUMBERS

At any given time, for any given insulation system, several parameters may affect Q_m and NQN. Specifically, the parameters mainly affecting these numbers are: Stator winding temperature, operating voltage, operating load, ambient temperature and humidity. It is beyond the scope of this paper to outline the influence of these parameters on the PD levels measured. Please refer to reference [12] for further information. However, the NQN and Q_m levels measured may fluctuate heavily depending on the above-mentioned parameters. Thus, for reliable trending of insulation aging, it is imperative that the PD trend curve be established at specific operating conditions.

NOVEL CONTINUOUS PD MONITOR

The new continuous on-line measurement system, PDTrac, constitutes a major improvement over the previous system, MotorTrac. The PDTrac system consists of three capacitive 80pF PD sensors and a PDTrac instrument. In addition to the fundamental data acquisition and data processing components, the PDTrac instrument may contain a sensor output module for summary number output to a local SCADA system, an operating condition input module for monitoring of operating conditions such as temperature and load as well as ambient temperature and humidity, an integrated alarm output module for setting

alarms in a local SCADA system and a communication module for remote access to the instrument. A software application allows data transfer to and from the instrument.

The basic installation details are as follows: One sensor is installed per phase as close to the machine terminations as possible – see Figure 3. Each PD sensor is connected to the PDTrac via shielded RG-58 coaxial wire routed in a grounded conduit. The PDTrac contains three outputs, one for each phase connected to each PD sensor, allowing for sophisticated PD detection equipment to be connected to the motor. A picture of the instrument box is given in Figure 4.

The PDTrac system may operate in one of two modes: Autonomous Mode or Remote Controlled Mode. In Autonomous Mode, the PDTrac system is operating autonomously while continuously monitoring the PD activity on the electrical equipment for warning of insulation failure. If the PD activity exceeds pre-defined alarm levels, an alarm will be set. The front panel of the device contains an alarm diode. In addition, using the Alarm Output Module, the PDTrac may be connected to a local SCADA system and thus provide warning to a central control room. Thus, in Autonomous Mode, the PDTrac system essentially constitutes an alarm system. The PDTrac device will continuously store NQN and Q_m summary numbers while monitoring the PD activity. The instrument can store up to two years of partial discharge data.



Figure 3: Picture of PD Coupler Installation at Motor Terminals

In Remote Controlled Mode, the PDTrac system acts as an alarm system but still having diagnostic capabilities. Specifically, in addition to obtaining NQN and Q_m trend curves for predefined operating conditions, 2D data plots – see Figure 1 – for identification of specific aging mechanisms may be obtained. Also, among other features available in Remote Controlled Mode is Internet access to the device from any remote client location via an ordinary Internet browser.

The functionality of this mode of operation is complex and thus cannot be discussed in great detail here. When operating in Remote Controlled Mode, a remote server controls the PDTrac instrument. Thus, the PDTrac instrument must be connected to a local network. The server periodically contacts the device to enquire if alarms have been set and/or to request acquisition of data for storage in a database for trend purposes. The PDTrac may be equipped with a operating condition input



Figure 4: Picture of the PDTrac instrument

module but full benefit from the complex functionality embedded in Remote Controlled Mode will appear when the server is connected to a SCADA system for monitoring of the operating condition of a given motor. Remote Controlled Mode is useful in the case a large number of motors are quipped with PDTracs and incidents thus occur frequently.

Seven years of experience of continuous on-line monitoring electrical equipment for PD activity has proven it to be necessary to establishing trend-curves at specific operating conditions. Hence, PDTracs contain powerful trigger algorithms allowing for data storage at specific operating conditions. These operating conditions triggers should be based on the machine ratings and its typical operating condition and may be defined prior to commissioning the PDTrac system. The implementation of operating condition triggers constitutes a significant improvement with respect to providing reliable alarms and, thus, reliable warning prior to equipment failure.

MEASUREMENT PHILOSOPHY

Since the continuous on-line monitor does not provide

phase resolved PD data, it is not possible to identify the specific aging mechanisms acting on the motor winding based on data acquired by the monitor alone. The measurement philosophy is outlined in Figure 5. Prior to initializing the installed continuous monitor, a phase resolved data plot of the PD activity acting on the winding should be obtained. Based on a set of phase resolved data, it is possible to identify the nature of various aging mechanisms acting on the stator winding.

Once the individual aging mechanisms are identified, an alarm triggers may be set. Sets of Magnitude Alarms based on NQN and Qm may be defined. Furthermore Rate Increase Alarms based on increases in Qm and NQN over time maybe defined as well. With respect to Magnitude Alarm levels, the 90 percentile for the cumulative distribution function for Qm for a given machine class may be used as basis for a magnitude alarm. The 2002 numbers are given in Table 1.

Hence, trending Qm and NQN over time, the motor monitor thus provides reliable information on the general overall health of the winding insulation. When a certain Qm or NQN level is reached, or the rate of increase in NQN and/or Qm exceeds a preset value, an alarm will be activated. This means the insulation of the motor has reached a predetermined critical state and detailed investigation of the winding is necessary. In most cases, acquisition of yet another phase resolved will identify the specific health of the insulation. If the user wishes to

assess the specific aging mechanisms acting on the motor winding, a phase resolved PD plot must be obtained. Certain aging mechanisms, such as surface PD in the endwinding area, can give rise to high Qm and NQN levels without posing an immediate risk for failure. High NQN and Qm values for other aging mechanisms, such as PD internal to the groundwall insulation in the slot part of the winding, does pose an immediate risk for stator winding failure.

Once the identity and severity of these mechanisms are identified, corrective maintenance measures may be performed. The PDTrac system thus allows for convenient and reliable assessment on the general health of the insulation system of electrical equipment.

CASE STUDY I: MOTOR A

Figure 6 shows a trend of daily NQN and Qm summary numbers for a 4.2 kV Epoxy-Mica

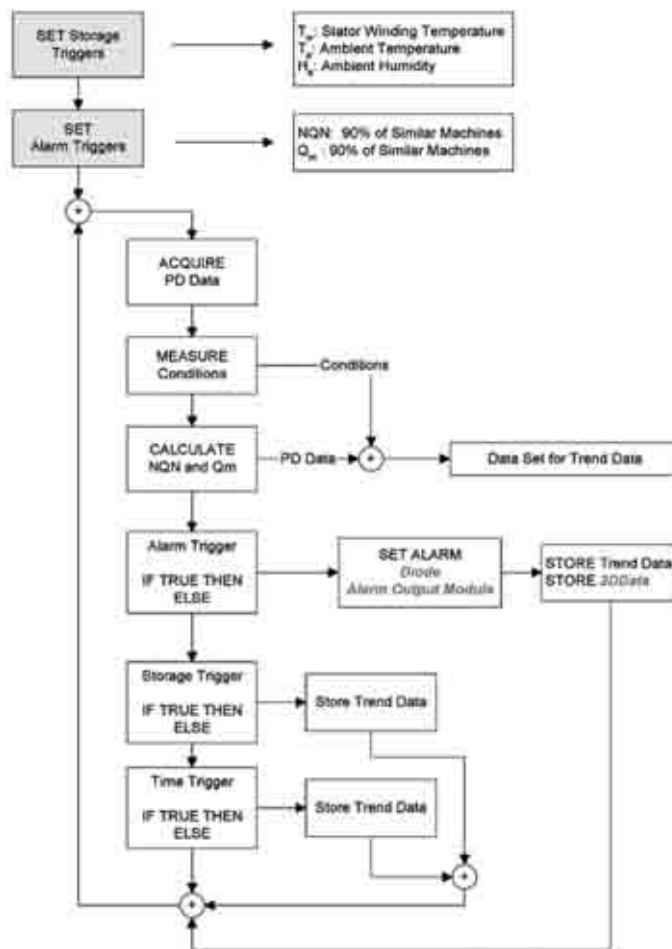


Figure 5: Outline of Measurement Philosophy

motor winding from 1970. The data was acquired between the 30th of April 1997 and the 30th of January 1998. For educational purposes, NQN- and Qm- have been omitted from the graph in Figure 6. NQN+ and Qm+ were at all times similar in value to NQN- and Qm-.

As demonstrated in Figure 6, the PD activity is generally fairly high, reaching a maximum Qm of 488mV and a minimum Qm of 80 mV. The average NQN+ throughout the period is 422 and the average Qm+ is 288 mV. It was mentioned earlier, that increases of a factor of two in NQN and Qm over a period of six months is an indication of rapid progression of the various aging mechanisms acting on a winding. Although the average increase over the period of April '97 to January '98 does not match this criterion, it can clearly be seen that the Qm and NQN numbers measured on this motor are high. That, in itself, gives rise to concern with respect to the health of the winding. According to Table 1, this machine periodically experiences Qm levels comparable to the top 10% of similar machines in service. Figure 6 clearly shows the changes in PD activity to be related to changes in the measured winding temperature. Specifically, both NQN and Qm levels decrease with decreasing stator-winding temperature and, consequently, NQN and Qm likewise increase with increasing stator-winding temperature. The influence of temperature thus explains the somewhat cyclic pattern of the overall PD activity measured. However, the PD levels measured overall are high and did thus give rise to concern.

ilar test conditions, the changes in PD activity cannot be attributed to temperature differences, etc. Therefore, the difference in PD activity between the two data sets is thus indicative of a change in the most predominant aging mechanism acting on the insulation system of this machine.

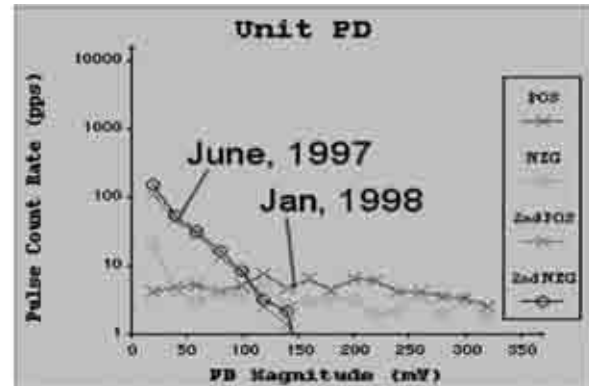


Figure 7: Pulse Height Analysis

To help investigate this problem further, a Pulse Phase Analysis of the two data sets was performed. The results of the analysis further supports the hypothesis of a change in the most predominant aging mechanism between the two tests. Figure 8

shows a Linear Pulse Density plot (Pulse Phase Analysis plot) of the two sets of data as displayed in Figure 7. The plot was created using a software program enhancing PD interpretation by graphical means.

The top plot in Figure 8 shows a cluster of negative and positive pulses to be centred at 75° and 255° respectively with reference to the ground-to-phase voltage. It can be shown that these pulses relate to phase-to-phase dependent PD located in the endwinding area [12]. The root cause of this activity may either be contamination of the endwinding or insufficient spacing between endwinding

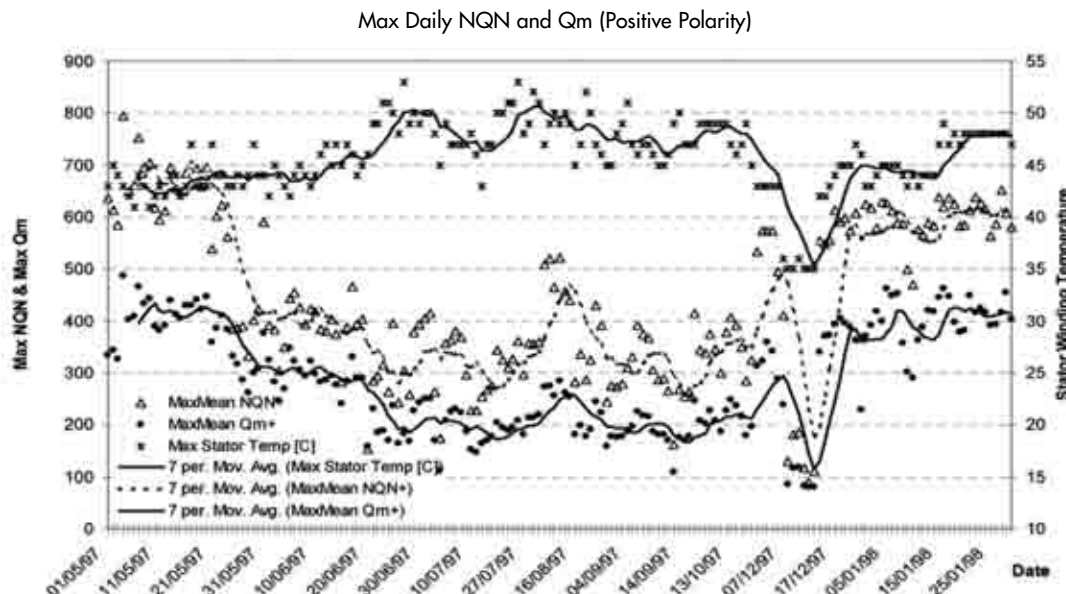


Figure 6: PD Trend for Motor A

Figure 7 depicts a pulse height analysis plot derived from two phase resolved data sets: The first set of data was obtained in June '97 and a second set of data was obtained in January '98. These two sets of data were acquired at similar operating conditions, i.e. 100% load and at comparable winding temperatures (93°C versus 88°C). As can be seen, the Pulse Height plots are quite different for the two tests: The June '97 data is moderately low magnitude wise, yielding a Qm of approximately 100mV, compared to that of January '98. Furthermore, the January '98 data predominately contain high magnitude pulses with low pulse counts. Since these two sets of data were acquired at sim-

ing coils.

The bottom plot in Figure 8 displays the PD activity approximately six months later. As can be seen, the PD activity was quite different. Again, a negative and a positive cluster of PD pulses can be found at 75° and 255° respectively with reference to the phase-to-ground voltage. The magnitudes measured are approximately six to eight times higher than those measured in June 1997. The shape of the two clusters is now quite different: An analysis of the shapes strongly suggests the activity to be related to partial discharges occurring along an insulation surface such as electrical tracking along endwindings or electri-

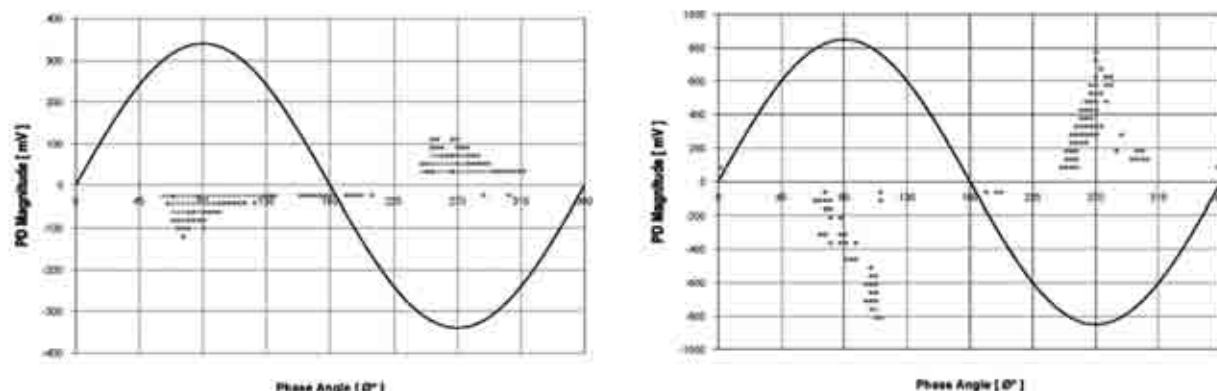


Figure 8: Top: June 1997. Load = 100%. Winding temp. = 93°C. Bottom: Jan. 1998. Load = 100%. Wind. Temp = 88°C

cal tracking along the cable lead terminations. The former was proven to be the case. A visual inspection of the endwinding area revealed a heavily polluted endwinding (oil contamination) and visible evidence of PD activity. Although giving high magnitude PD pulses, this discharge activity usually takes a significant time to evolve into a failure. Corrective maintenance, i.e. cleaning of the endwinding area, was postponed until the next scheduled outage.

The PD activity measured via the continuous on-line monitor indicated high PD activity which, again, gave rise to concern with respect to the health of the winding. Based on the PD activity, it was evident that the motor (and the electrical system connected to the motor) was in need of corrective maintenance. This was confirmed via a visual inspection of the endwinding area. With this in mind, the motor was allowed to continue operating to help acquire further PD data relating to this specific aging mechanism. Eventually, the cable terminations failed and the motor was put out of service and new cable leads were installed.

CONCLUSIONS

On-line PD measurements is a proven technology for detection of most insulation problems well in advance of equipment failure. Based on the last seven years of experience with continuous on-line PD monitors, a new continuous on-line PD monitor, PDTrac, for motors, switchgear and dry-type transformers has been developed. The monitor constitutes a significant improvement of the older technology. Specifically, it allows for summary data to be stored at predefined operating condition thus establishing reliable trend curves based on which alarms may be triggered. The monitor allows for definition of both magnitude alarms and trend alarms. The monitor may operate in Autonomous Mode or Remote Controlled Mode. The later mode of operation, among other functionalities, allows the user to access a PDTrac remotely via the Internet. In general, Remote Controlled Mode provides functionality needed when implementing a CBM program for a large number of electrical equipment.

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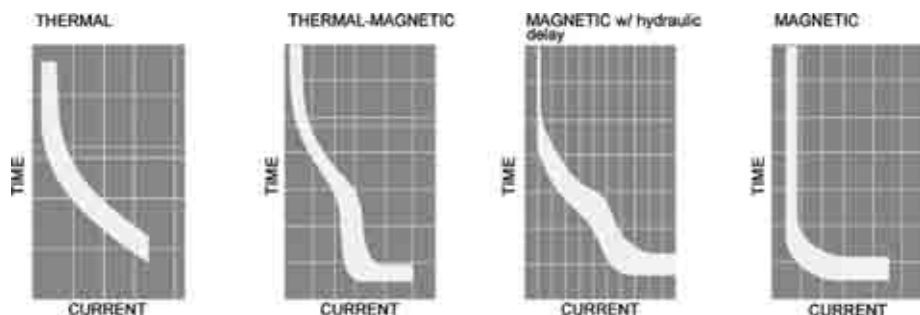
THE DIRTY DOZEN: THE 12 MOST COMMON MISTAKES OF SPECIFYING CIRCUIT PROTECTION FOR EQUIPMENT

Courtesy of E-T-A Circuit Breakers

It's only a circuit breaker. Yet there is enough complexity and confusion when it comes to specifying circuit protection that many engineers are designing equipment with too little or too much protection. Under protected circuits leave equipment vulnerable to damaging electrical surges. Over protected circuits add cost and can lead to nuisance tripping. Like Goldilocks and the three bears, the goal is to specify circuit protection that is 'just right'.

As a leading manufacturer of circuit breakers for more than 50 years, E-T-A Circuit Breakers has helped countless engineers navigate the specification process. Over the years, we have encountered many misconceptions, and we have selected the 12 most common pitfalls for this white paper. It is our hope that, by sharing our expertise, you will avoid these mistakes and protect your designs with 'just right' circuit protection.

1. SPECIFYING THE WRONG CIRCUIT BREAKER TYPE FOR THE APPLICATION



The number one mistake design engineers make is specifying the wrong circuit breaker technology for the application. There are four choices of circuit breaker technology: thermal, magnetic, thermal-magnetic and high performance. Each has a different trip profile in relation to time and current, and each has distinct mechanical characteristics.

Magnetic circuit breakers operate via a solenoid, and trip nearly instantly as soon as the threshold current has been reached. This type is appropriate for printed circuit board applications and impulse disconnection in control applications. Often, a magnetic circuit breaker is combined with a hydraulic delay to make it tolerant of current surges. Preferably, the circuit breaker is mounted in a horizontal position to prevent gravity from influencing the movement of the solenoid. If mounted in a non-horizontal position, derating may be needed.

Thermal circuit breakers incorporate a heat-responsive

bimetal strip or disk.

This type has a slower characteristic curve that discriminates between safe temporary surges and prolonged overloads. It is appropriate for machinery or vehicles where high current in-rushes accompany the start of electric motors, transformers, and solenoids.

Thermal-magnetic circuit breakers combine the benefits of a thermal and magnetic circuit breaker: a delay that avoids nuisance tripping caused by normal inrush current and fast response at high currents. High overcurrents cause the solenoid to trigger the release mechanism rapidly, while the thermal mechanism responds to prolonged low value overloads. They have a characteristic two-step trip profile that provides fast short-circuit protection of expensive electrical systems while minimizing the risk of disrupted system operation.

Where reliable operation under adverse conditions is required, high performance circuit breakers provide high interrupting capacity and excellent environmental specifications.

Typically, these circuit breakers are specially designed for aerospace, defense, and similar heavy-duty applications where extreme vibration, mechanical shock, and other conditions are present, and where circuit breaker performance is absolutely critical. For high performance applications, thermal circuit breakers have a compensating element that eliminates sensitivity to ambient temperature.

Many engineers seek specification assistance from the support desks of circuit breaker manufacturers. However, be wary of advice from manufacturers who make only one type of circuit breaker.

2. SPECIFYING TOO HIGH A RATING IN AN EFFORT TO AVOID NUISANCE TRIPPING CAUSED BY IN-RUSH OR TRANSIENT CURRENTS

Most engineers are concerned about nuisance tripping, as they should be, but they often specify a circuit breaker rated much higher than they should. Part of the reason is confusion between fuses and circuit breakers. Engineers are used to oversizing fuses as a way to prevent nuisance tripping. However, there is no need to oversize a circuit breaker.

Unlike a fuse rating, a circuit breaker rating tells you the maximum current that the circuit breaker will consistently maintain in ambient room temperature.

Thus, a 10A circuit breaker will maintain a 10A current without nuisance tripping.

In fact, a typical 4A circuit breaker with a slow trip profile will tolerate a temporary 10A current surge without nuisance tripping.

Often times, nuisance tripping is caused by in-rush currents associated with certain electrical components - primarily motors, transformers, solenoids, and big capacitors. In such cases, the designer needs to specify a circuit breaker that has a delay. Thermal circuit breakers have a natural delay, and magnetic circuit breakers can have added hydraulic delays. Match the delay to the duration of the expected in-rush currents.

3. FAILURE TO PROVIDE SPACING IN DESIGN

It is important to maintain recommended minimum spacing requirements between non-temperature-compensated thermal circuit breakers. A mere 1 mm spacing between breakers is all that is required. Without this tiny thermal gap, the circuit breakers can heat up and increase the sensitivity of the bimetal trip mechanism. If the breakers must touch each other, derate them to 80% of their normal amperage rating.

4. OVER SPECIFYING OR AMBIGUOUSLY SPECIFYING THE DEGREE OF PROTECTION

Terms such as drip-proof, ignition protection, water splash protection, and dustproof are in common usage but may be misleading unless standard definitions are applied. When specifying, use the established standards as a measure, such as EN 60529/IEC 529, which defines Degree of protection of Electrical Equipment.



Using these standards, decide which protection is correct for the application.

For example, ignition protection makes sense if the breaker is installed in the engine compartment of a boat, but is not needed if installed in the boat panel. A combination switch-breaker installed in medical equipment might need a water splash protection rating, but it probably does not need a rating for continuous immersion in water. Truly watertight and dust-tight circuit breakers are available, but they are expensive and usually unnecessary.

Truly watertight and dust-tight circuit breakers are available, but they are expensive and usually unnecessary.

5. SELECTING THE CORRECT ACTUATION

Circuit breakers are reset manually by means of an actuator. There are many types of actuators, including press-to-reset, push-pull, push-push, rocker, toggle, baton, and press-to-reset with manual release. The actuator type is more than a cosmetic consideration. For example, critical applications usually call for push-pull style actuators, because these are the most resistant to accidental actuation.

The type of actuator you select will be determined by the location of the circuit breaker, the need for illumination, the need for human operator safety or convenience, and the consequences of accidental engagement.

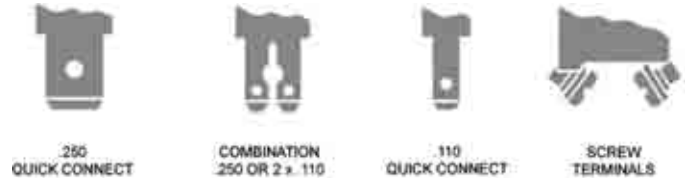
6. FAILING TO CONSIDER USING CIRCUIT BREAKERS AS ON/OFF SWITCHES

Many circuit breakers are designed to be both a breaker

and on/off switch. The advantages of a combination device are a reduction in components, less consumption of panel space, reduced wiring and increased protection over ordinary switches.

7. SPECIFYING THE WRONG TYPE OF TERMINAL

Circuit breakers with plug-in style quick connect terminals simplify installation and replacement (they may also be soldered). Screw terminal connections are more secure and suited for high current and high-vibration environments. Quick connect terminals may be used for circuit breakers rated up to 25A.



8. SPECIFYING A FUSE WHEN A CIRCUIT BREAKER WOULD BE BETTER

Although fuses provide inexpensive circuit protection, the cost savings should be weighed against the low total cost of ownership of circuit breakers.

Foremost, circuit breakers can be quickly reset, enabling the circuit to be restored with a minimum of downtime. In addition, there is no assurance that a replacement fuse will be of the proper rating. If a fuse is replaced by a higher rated fuse, overheating and catastrophic equipment failure may occur.

Circuit breaker performance is relatively stable over time, but as fuses age, their trip characteristics change. This may lead to nuisance tripping and increased downtime.

Circuit breakers offer designers more options than do fuses. An auxiliary contact may be added that can communicate an alarm condition to an LED indicator or process software. In addition, a circuit breaker can be combined with a switch, saving space and adding overload protection. Remote trip is another option available with circuit breakers but not with fuses.

Furthermore, unlike fuses, circuit breakers have a variety of types and trip profiles, and therefore can be more precisely matched to loads and environment.

Finally, fuses cannot be tested without destroying them. How can you be sure the fuse you specify will open if there is an overload?

9. SPECIFYING THE WRONG TYPE OF CIRCUIT BREAKER FOR A HIGH VIBRATION ENVIRONMENT

Typically, the trigger of a magnetic circuit breaker is a hinged metal armature that closes in response to the movement of a magnetic coil. This design makes magnetic circuit breakers (and magnetic-hydraulic circuit breakers) particularly vulnerable to vibration, which can cause the armature to close prematurely.

In contrast, a typical thermal circuit breaker is comprised of a thermal actuator and a mechanical latch.

Thermal circuit breakers are therefore highly tolerant of shock and vibration.



If a magnetic circuit breaker is the best type for the application, its vibration resistance can be improved by using a push-pull style actuator. This type of actuator has a latching design.

10. FAILURE TO DERATE

As a rule of thumb, the circuit breaker should be rated for 100 percent of the load. However, some applications require a circuit breaker to operate continuously in either high or low temperatures. In these cases, follow the manufacturer's guidelines for derating. For example, an application calling for 10A protection requires a 12A rated thermal circuit breaker when it is operated at 50 degrees C.

11. DERATING WHEN IT IS NOT NECESSARY

The performance of a thermal circuit breaker is sensitive to fluctuations in ambient temperature. It will trip at higher amperage in a cold environment, and it will trip at lower amperage in a hot environment.

One common mistake is to assume that derating is necessary for thermal circuit breakers in environments that experience rises in ambient temperature.

Actually, the performance of a thermal circuit breaker tracks the performance needs of the system, assuming it is exposed to the same heat source. For example, motor windings need more protection from overheating at 90 degrees C than the same windings need at 20 degrees C. A cold motor requires more in-rush current to get started, and therefore a longer delay is advantageous on a cold day.

Another misconception is that magnetic-hydraulic style circuit breakers are immune to performance changes in rising ambient temperatures. On the contrary, these circuit breakers contain a dashpot with a liquid core that becomes more fluid at higher temperature, reducing the time of the hydraulic delay.

12. OVER SPECIFYING INTERRUPTING CAPACITY

Interrupting capacity is the maximum amperage a circuit breaker can safely interrupt. Circuit breaker manufacturers publish this specification along with the number of times the circuit breaker will perform this feat. For example, E-T-A publishes two types of interrupting capacity specifications. One is called

Icn, or Normal Interrupting Capacity. Icn is the highest current the circuit breaker can interrupt repeatably (three times minimum, per IEC934/EN60934 PC2). Icn gives a rough idea of circuit breaker quality. The other specification is UL1077 Interrupting Capacity. UL1077 (or IEC934 / EN60934 PC1) is the maximum current a circuit breaker can safely interrupt at least one time without causing a fire hazard.

To comply with various standards, engineers must specify circuit breakers with adequate interrupting capacity. Unfortunately, applying the appropriate standard may be confusing.

For example, UL 489 requires interrupting capacity from 5000A and above.

While perfectly appropriate for main power distribution applications, this standard has been perpetuated in other industries, where the short circuit rating, governed by circuit resistance, is much lower. The UL 1077 standard for supplementary protectors covers the short circuit test and lists the current at which the breaker was tested.

Although certain devices such as UL 489 molded case circuit breakers have higher interrupting capacities, they may not be well suited for lower current applications where precise overload protection and adequate short circuit protection is better provided by a UL1077 supplementary protector.

The telecom industry is particularly prone to overspecifying interrupting capacity because some vendors of circuit breakers for DC telecom equipment also market the same circuit breakers for AC power distribution. Although the potential supply of current seems high in telecom applications, the realistic amount of current available is actually far less, due to line loss. In most telecom applications, a circuit breaker with 2000A interrupting capacity is more than adequate.

SUMMARY

If you keep these tips in mind, it is easy to specify the right measure of circuit protection at the lowest cost. Start the selection process by working to truly understand your load. Then decide which type of circuit breaker is best suited to your application. Avoid the common specifying mistakes, and you will be rewarded with a reliable design.

INNOVATION TO REALITY: INTRODUCING STATE-OF-THE-ART PROTECTION AND MONITORING TO EXISTING LOW-VOLTAGE SWITCHGEAR

By Sherwood Reber, Lafarge North America; Michael Pintar and Christopher Eaves, General Electric

A large array of components with communications capabilities exists for constructing protection, monitoring, and control systems for power distribution equipment (switchgear). While most of these components or devices perform multiple functions, a typical application will contain at least several different devices that must be interconnected to function as a complete system.

An example might be multifunction meters coupled with multifunction protective relays, and a programmable logic controller for a complete system. Could it be possible to take the functions of multiple microprocessor-based devices and combine those functions into a single-processor system? Would the new system be able to execute instructions for fast acting over-current protection while gathering simultaneous metering data from every circuit breaker in the equipment line-up?

In this article, the authors discuss a unique approach to low-voltage switchgear protection and the process of transitioning this concept to a real-world application. The article describes the architecture and functionality of this approach and explains how a centrally controlled system can provide advanced monitoring and protection functions much more effectively than existing systems.

Installation and field-testing are important steps in the process of introducing new technology. This article will describe why retrofitting an existing switchgear lineup may be preferable to starting with new switchgear. It will also describe the considerable planning involved in the retrofit process to minimize the effect on the customer's operations.

The article concludes with a discussion of how well the system functioned in an actual operating environment.

I. INTRODUCTION

A. BACKGROUND

Communicating devices and associated networks are increasingly common in electrical power distribution equipment. The networks provide the important connection among individual devices, such as trip units, meters, and protective relays, for gathering and reporting critical power system information. In low-voltage power systems (600 V and below), a network of communicating devices can provide supervisory control functions, gather substation electrical data, and report event status to a central control computer.

A challenge in working with communicating devices has been handling large amounts of data from multiple devices in a workable time frame.

Speeds and bandwidth on commercially available networks have recently reached levels at which it is reasonable to consider gathering data from every circuit in a substation (up to

30 circuits) and use that data to perform real-time control and protection functions. Channeling all these data to one central processor located in the low-voltage substation provides an opportunity to perform protection, control, and monitoring functions that are either not possible with conventional hardware and/or software or are extremely difficult to implement in electrical distribution equipment.

B. SHORTCOMINGS OF PRESENT-DAY COMMUNICATION SYSTEMS

Although modern communication networks have the speed and bandwidth to communicate with many devices, variable latency caused by communication delays, device response time, and the amount of information requested from each device has relegated communication devices to supervisory and data-gathering functions. In order to add protection, such as overcurrent tripping, to the list of functions handled by the network, a fast, reliable, and deterministic communication system is necessary.

Variables affecting system response, such as the number of communicating devices and the length of the message to and from the device, can make the system response time after an event (electrical fault) not only difficult to predict, but also slow compared to the time required by a single device to execute its own event response. Certain types of information from a device can be assigned to high priority interrupts, but the system response is not always deterministic, nor is the performance predictable. Higher-speed networks, including Ethernet, can provide very fast communication rates, but the protocols employed do not provide the necessary predictable and deterministic response times. Protocols specifically designed for machine and device control offer promising capabilities in data rate, scalability, and reliability, but none provided the desired fast, reliable, and deterministic communication.

C. A DIFFERENT APPROACH TO MONITORING AND PROTECTION

The concept discussed in this paper uses a methodology different from that of all other electrical equipment systems to date.

Communication is based on the capabilities of Ethernet, while removing the time variation introduced by collision-detection, multiple-access (CSMA/CD) protocols. Communication is structured to yield fixed latency and subcycle transmission times between a central processor and all the devices in the system. Fast communication and fixed latency are key enablers for using a communication network to perform critical control, monitoring, and protection functions.

A second distinction is in the types of information carried on the network. Rather than processed summary information

captured, created, and stored by such devices as trip units, meters, or relays, the actual raw parametric or discrete electrical data and device physical status are carried on the network. The data sent from the devices to the central processor are the actual voltages, currents, and device status. As a result, any microprocessor on the network has complete system wide data with which to make decisions. It can operate any or all devices based on information derived for as many devices as the control and protection algorithms require.

The architecture discussed here is centralized, with one microprocessor responsible for all system functions. Alternate architectures, such as distributed and semi-distributed, were considered, but the central processor architecture provides the best performance. Figure 1 shows the centralized architecture applied to a typical lineup of low-voltage switchgear, with a central computer performing the control and protection functions and each breaker acting as a node on the network. The key advantage of this architecture is that the single processor has the information from all nodes simultaneously. Thus, protection and control schemes can be designed that consider the values of electrical signals, such as current magnitude and phase angle, at one or all circuit breakers in the system with equal ease. This allows the implementation of circuit-specific zone-protection functions as easily as a simple overcurrent function at a single circuit breaker.

The following are examples of the advanced protective and monitoring functions possible with a single-processor archi-

ture is between a main or tie circuit breaker and a branch feeder circuit breaker.

- **Bus differential** - A type of bus fault protection seldom used in low voltage equipment due to the costs associated with multiple current sensors on each circuit breaker and the need for a set of sensitive (and usually costly) protective relays.

Sensitive bus differential protection can significantly reduce the damage associated with arcing faults.

- **Dynamic zone protection** based on system configuration - Provides the ability to dynamically adjust overcurrent protective settings on upstream breakers based on the settings of a downstream breaker sensing a fault. Back-up protection provided by the main or tie circuit breaker can be much tighter to the feeder breaker that is sensing and attempting to clear the fault. Traditionally, main and tie circuit breakers are set with higher overcurrent pick-up and delay settings to be selective with the largest feeder circuit breaker on a bus. Closely set back-up overcurrent protection for smaller feeders is sacrificed when the mains and ties are set to be selective with larger feeders. Dynamic zone protection could provide the closest overcurrent back-up protection for all feeders on a bus, independent of the differences in trip settings between main and feeder breakers.

- **Simultaneous event reporting** on all devices - The system could be capable of recording any change in status of any circuit breaker or system component and could generate an alarm and/or send an electronic notification detailing the event. An event triggered by a fault could generate a simultaneous capture of all voltages and currents on all circuit breakers within the switchgear line-up. This synchronized collection of data on all circuit breakers during an event can provide the critical information needed for determining the cause of the circuit breaker trip and getting the majority of the system back on line quickly.

II. FROM CONCEPT TO REAL-WORLD APPLICATION

This technology represents a significant departure from traditional systems. As with any technology that is significantly different from traditional systems, field experience is essential.

Testing in a laboratory is a necessary first step but does not cover three significant areas.

- 1) **Laboratory Testing Covers only Known Usage Cases:** For this system, a database management tool linked the test cases to the product requirements. Test procedures were based on the product specifications and detailed requirements for the systems. Test results and pass/fail criteria were linked back to the specifics of the product requirements. The engineers also expanded the test cases by performing failure mode effects analysis (FMEA) to add unexpected cases, providing more than simple coverage. Although testing is thorough, the unexpected field situation can still be missed.

ing is thorough, the unexpected field situation can still be missed.

- 2) **The Environment Is Different:** In particular, the electromagnetic (EM) field caused by motor loads, transformer inrush, and switching transients is different in the field. Laboratory testing to ANSI C90.1 is performed prior to beta testing to cover high-frequency, high electric field situations. Other laboratory testing for the influence of high-strength, low-

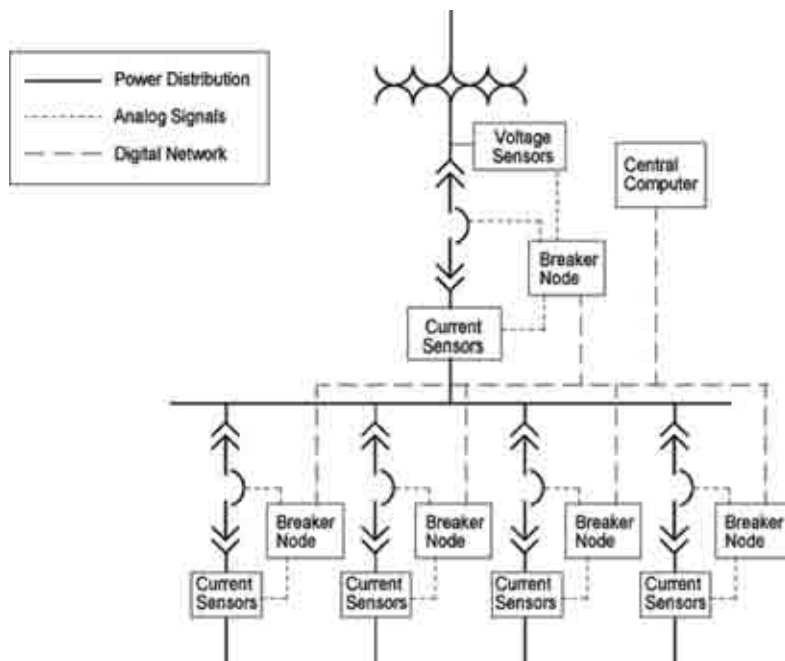


Fig. 1. Centralized architecture applied to a typical low voltage switchgear lineup.

ture where all devices provide data simultaneously.

- **Multiple-source ground fault** - Includes simple main-tie-main configurations with multiple neutral-to-ground bonding connections to more complex systems incorporating utility transformers, emergency generators, paralleling equipment, uninterruptible power sources, and bypass breakers.

- **Zone-selective interlocking** - Reduces the delay time for overcurrent tripping (short time or ground fault) when the fault

frequency magnetic fields is also performed specifically because such fields are present in switchgear.

3) Customer Interface: Unlike previous, and some current, switchgear designs in which the devices are black boxes with minimal user interface, this new concept includes a touch screen human-machine interface (HMI). The HMI provides full system data, including electrical parameters (current, voltage, and power), status (breakers closed or open), and events (breakers tripped, alarm set points exceeded); serves as the input device for all of the system settings; and allows complete operation of the switchgear.

To perform this full range of features, the HMI requires multiple screens, menus, and options. The HMI designers, based on feedback from a customer focus group, initially lay out the screens.

But the best test of the information presented and the navigation through the screens comes from day-to-day operation by individuals who are not intimate with the design of the product. The HMI should have a familiar “feel” and operation, like other available touch screen or input and monitoring devices. A primary is to make the HMI as intuitive as possible in its operation.

A. WHY A RETROFIT?

The primary reason for choosing an existing installation for the beta site was to introduce this new concept in an operation that was already electrically stable. With new installations, unanticipated issues frequently arise while the system is being commissioned. Often the issues are related to the primary power, not the control and monitoring system, and can be very time consuming to resolve. The goal of the beta site is to evaluate the operation of the new system in a real-world environment. The stable electrical operation of an existing system simplified the root cause analysis of field-identified issues, as well as the subsequent testing of potential resolutions.

The retrofit was performed on a low-voltage switchgear installation that already had some power-monitoring capability. This monitoring system was left in place when the gear was retrofitted with the new system hardware. The existing monitoring system provided an independent source of data to which new system data could be compared.

The choice of a retrofit installation versus a new installation also provided a much higher probability that the system installation and commissioning dates would be maintained. In a new installation, starting the beta equipment is dependent on energizing the switchgear. Energizing new switchgear is dependent upon the construction schedule of the new facility. Any delay in construction, including uncontrollable factors like weather, delays the start of the beta testing. In extreme cases, construction delays can extend for months. The retrofit of this beta site was scheduled during the equipment shutdown for the upgrade of the substation transformer. The actual date of the retrofit was within 2 weeks of the original schedule developed several months earlier.

B. THE SHADOW SYSTEM

The beta site installation had to provide critical information about the function of the system in an actual electrical environment by monitoring and reporting the power system’s electrical data. Since the system provides both monitoring and protection, it is designed to react to overcurrents and other electrical fault conditions. It was critical that the system operation be

tracked to verify its response to electrical conditions in the substation, but equally critical that the system not cause any shut-down of the breakers in the switchgear.

This was accomplished with remote access to the system events log. Comparing the reports from the events log with the on-site power management system and weekly feedback from the site allowed tracking and verification of unexpected situations without disrupting plant operations.

C. SECONDARY OBJECTIVE OF THE RETROFIT

The beta retrofit also provided an opportunity to evaluate the feasibility of this new product as a retrofit into existing switchgear. Typically, retrofitting switchgear with new hardware is a difficult and time-consuming process.

Some issues that could be encountered when retrofitting existing switchgear with traditional devices (intelligent and non-intelligent) include the following:

- The retrofit usually requires that the breakers be upgraded with new electronic trips. If this includes current transformer or current sensor replacement, some bus bar disassembly and reassembly may be required.
 - Adding new features to the equipment may mean adding new intelligent electronic devices (IEDs). Disassembly of the switchgear may be required to mount new IEDs.
 - Wiring – Each added IED must be wired to its associated circuit breaker and sensor(s) and interconnected to other IEDs within the switchgear.
 - Wiring is probably the most difficult task, since exact mounting locations may not be known. Also, interconnections between IEDs may require point-to-point wiring rather than a multi-wire harness.
 - Different functions require different interconnects, uniquely designed and built on site.
- Summary of the new system retrofit:
- Circuit breaker upgrades were simple, with the addition of a shunt trip and auxiliary switch to each breaker.
 - There was a standard set of hardware to install. The central processor handles all protection, monitoring, and control functions.

Current and voltage signals have standard designs and locations within the switchgear.

The IED for the circuit breaker mounts in a standard location above each circuit breaker cubicle.

- Wiring was standard at the breaker and throughout the switchgear. Interconnect points and device locations were known. This made it possible to prefabricate the majority of mountings and harnesses. The interface to the circuit breaker was also well defined

III. DETAILS OF THE NEW SYSTEM RETROFIT

Once a potential beta site was identified, the beta team obtained a copy of the electronic drawing files to evaluate the suitability of the switchgear. One of the primary factors in determining the site’s suitability was confirming that the new system had the functionality required by the existing equipment. When it was determined that the functionality matched, the remainder of the beta issues were resolved and a customer agreement was reached.

The beta site identified and agreed upon was the Lafarge North America plant in Whitehall, PA. A 500kVA unit substation had been designed and manufactured in late 2001 and was installed in early 2002, as shown in Figure 2. The substation is

used to feed 480 volt loads for the quarry limestone crushing systems, raw material receiving, and the associated transport systems to storage silos. The 480 volt distribution equipment consists of five-800 amp frame feeder circuit breakers and provisions for one future 800 amp frame circuit breaker, as shown in Figure 3.



Figure 2. 500kVA Unit Substation



Figure 3. Low Voltage Switchgear Units

A. DESIGNED UPFRONT

Detailed manufacturing documentation provided by the switchgear factory allowed the beta team to design the new system in the engineering office before visiting the site. This was a key step in the successful installation process. The detailed engineering design included a complete bill of material for the new system (all hardware items, including terminal blocks, brackets, fasteners, terminals, and the major system components), detailed schematics of the breaker element and the switchgear, and detailed mechanical layouts of system component locations.

During the design process, the decision was made to locate the major system components — the central processors, UPS, and communication switches — in a separate switchgear section. This decision was initially made because auxiliary equipment originally designed into the switchgear occupied the space where the new components would typically be located. As the project progressed, the decision to locate these components outside the switchgear enclosure became an obvious benefit.

As part of the beta test process, the new equipment was monitored and upgraded as new releases with advanced features were introduced.

Having some of the system components in a separate section allowed easier access without the concern of exposing or disturbing any 480V equipment. This separate section has only 120V control power supplied by the switchgear control power transformer.

B. STRUCTURED DESIGN

The new system uses a structured hardware design, regardless of the switchgear size or functionality. This fact enabled the gear to be quickly and completely designed from the factory drawings without visiting the site. There are six primary design aspects of the new system: breaker compartment elements, communications network, central computers, control power, voltage transformers (VT), and HMI.

The breaker compartment elements consist of the phase current transformers (CT), the node electronics (node), and the interconnection wiring to the circuit breaker. The CTs are designed as three-phase units in single molded enclosures that mount to the breaker compartment rear barrier.

Each three-phase CT includes open-circuit protection and the harness for connection to the node. For four-wire applications, a current sensor is added to the neutral to provide the fourth current input to the central computer.

The node is the interface between the circuit breaker and the central computer and also provides the analog-to-digital conversion of the current and voltage signals for the central computer. The node has standard multi-pin connectors for the current, voltage, control power, and communication wire harnesses. A terminal block was added to the breaker compartment for connecting the control power distribution in the switchgear to the node harness. The breaker cubicle already had terminal block points dedicated for breaker accessories, such as the auxiliary switch and the shunt trip. An interconnect harness was designed to connect the breaker terminal block to the node. Because all breaker compartment wiring is standard, the harness designed for one breaker could be duplicated for each of the breakers in the switchgear.

The communications network uses two commercial, off-the-shelf, Ethernet network switches. Each node has two communication ports, one for each network switch. Dual communication networks were used to eliminate single points of failure. A network cable connects each switch to its respective central computer.

REDUNDANT SINGLE-PROCESSOR INDUSTRIAL COMPUTERS

The central computer compartment houses the two central computers, as shown in Figure 4, and requires only control power connections and the network connection from the network switches.

Because this site used an auxiliary section for the com-



Figure 4. Redundant Single-Processor Industrial Computers

puter compartment, the network switches were located in the switchgear near the nodes. Only two network cables are required to connect the switches to the central computers in the auxiliary section. The central computer compartment was outfitted with additional communication equipment to provide remote access to the system, so the design team could monitor it without traveling to the site.

Control power consists of two independent 120V AC sources feeding control power transfer relays which, in turn, provide input power to two uninterruptible power supplies (UPS) as shown in Figure 5. The outputs from the UPSs provide two independent power distribution circuits to the central computer compartment and each breaker compartment. All terminal



Figure 5. Redundant Uninterruptible Power Supplies

points associated with control power distribution are dedicated and consistent throughout the switchgear, including the breaker compartments and the computer compartment, simplifying the wiring design.

Although the standard design is based on two independent control power sources, the beta site switchgear had only a single control power transformer. The two inputs to the control power transfer relays were taken from individual windings on the secondary of the switchgear-mounted control power transformer. In a new-equipment application or in a full retrofit application, the standard design with two independent control power sources would be used.

Voltage transformers convert bus voltages to a level usable by the system. The beta site power transformer has a 480 V wye secondary. A three phase, wye-wye voltage transformer provided the required 18 V signal to the node. The system presents less than 1 VA of additional burden, so the VTs were connected to the load side of the same fuses used for the existing metering voltage transformers. Since there was only one 480 V source for the beta site switchgear, only one voltage input was needed for the entire system.

The secondary of the VT was connected directly to a main node in the switchgear–transformer transition section.

The HMI mounts in an instrument compartment within the switchgear lineup or in a nearby auxiliary section, as shown in Figure 6. The HMI is connected to the system via a communication cable and requires control power from the control power distribution in the switchgear. The touch screen on the HMI provides variable access to substation electrical data, status and event information for the substation, and control of the circuit breakers.

C. PREFABRICATED HARDWARE FOR THE RETROFIT

Two prototype switchgear sections, of the same type as used on the switchgear shipped to the beta site, were acquired for the engineering test lab.

The prototype gear was used to verify the mechanical fit of all the components and to define wiring harness lengths.

1) Mechanical Parts: All of the necessary brackets, wire tie-down points, terminal blocks, and current transformers designed for the gear were assembled into the prototype gear to



Figure 6. Human-Machine Interface (HMI) With Touch Screen

insure proper fit. The majority of the mechanical mountings used existing hardware and pilot holes in the gear. This dramatically reduced installation time by eliminating field-drilling of barriers and panels.

Installation of most of the components simply required removal of some hardware and then reinstallation with the system components.

2) Wire Harnesses: The prototype switchgear was used to generate detailed configurations of the wire harnesses to be used in the switchgear. Due to the common design of the control power distribution, a small number of unique harnesses were required for the entire beta site installation.

With the detailed definition of the wire lengths and terminations, the factory manufactured the complete harnesses.

The harnesses connecting the node to the CTs, control power, and the circuit breakers were also prefabricated with the multipin node connectors on one end and the correct terminal type and wire marker on the other end.

3) Auxiliary Section: Mounting the control power transfer relays, UPSs, and central computers in an auxiliary section allowed that section to be assembled and completely wired in the factory. It was then shipped to the site and installed. One problem was that the exact location of the auxiliary section was unknown, so the harnesses could not be fabricated complete. The switchgear ends of the harnesses were finished, but the auxiliary section end was unterminated, with wire markers only. The wires were cut and terminated in the auxiliary section before control power was connected.

D. PROCEDURES

With the design completed upfront, the statement of work for the actual retrofit activities could now be developed. All the components to be installed and all the wiring to be added or modified was now known. Having the prototype gear in the engineering lab provided the opportunity to define the tasks for the individuals who would be working on the retrofit. While the structured design of the system allowed the outline of the work to be developed, the prototype switchgear sections allowed detailed installation procedures to be defined. The procedures were an invaluable part of the retrofit process, particularly with the limited time available during the shutdown. The procedures also helped identify dependent and independent tasks and the order in which they had to be performed. Reviewing the detailed procedures helped insure that no tasks were omitted.

E. PLANNING – PREWORK, SHUTDOWN CRITICAL, POSTSHUTDOWN

Once the detailed bills of material and procedures were completed, the work was broken down into prework, shutdown, and post-shutdown activities.

1) Prework: This was coordinated with the customer around their normal maintenance schedule and the switchgear shutdown to replace the power transformer. The facility normally shuts down a section of the plant on Wednesdays.

During these weekly maintenance shutdowns, individual breakers were removed from the switchgear for installation of shunt trips and auxiliary switches before the major equipment shutdown. The auxiliary section and the wireway connecting it to the switchgear were also installed in the substation room before the shutdown.

2) Shutdown: The critical tasks to be performed during the primary shutdown included installation of the three-phase CTs, nodes, and associated wiring in each breaker compart-

ment; installation of the voltage transformers and communication network switches; and installation of the interconnecting wiring between the switchgear and the auxiliary section. All of these tasks were performed on or near the 480 V bus and only when the switchgear was shut down.

3) Post-shutdown: Tasks that were completed after the switchgear was reenergized included termination of the interconnecting wiring in the auxiliary section and installation of the HMI in the switchgear instrument compartment door. The last task was the startup and commissioning of the system. Having the bulk of the system hardware components in an auxiliary section proved to be a major benefit and is recommended for any retrofit application. Although the system is designed to reside entirely in the switchgear, the auxiliary section reduces the shutdown work scope and provides an opportunity to monitor and operate the switchgear from a safe distance.

F. EXPERIENCED, TRAINED RETROFIT TEAM

The retrofit team consisted of two field service engineers and two factory engineers. All four have multiple years of switchgear experience; one had previous experience at the site and two were trained in the system hardware installation using the engineering lab prototype switchgear. This proved invaluable during the retrofit. Knowing the components, interconnections, harnesses and terminal points and the order in which the tasks had to be performed meant that the work progressed continuously and orderly throughout the shutdown. The structured system design insures that the majority of the components and connections are the same, regardless of the gear specifics. Once trained on installing the system in a switchgear lineup, the engineer finds the process similar, with a few minor exceptions, for any lineup of the same type of equipment.

G. THE RETROFIT PROCESS

1) Pre-shutdown: Before the major shutdown, the shunt trip and auxiliary switch kits, with the installation procedures, were shipped to the site.

All of the breaker updates were performed over the course of several Wednesday shutdowns.

All of the components, harnesses, and hardware were packaged into working groups and shipped to the site. The complete bills of material facilitated getting all the necessary parts on site before the shutdown. A missing component, large or small, can be catastrophic during the limited time of a shutdown. Special tools needed for the installation or for repairing any damaged parts, such as a connector, were also on site.

2) Shutdown: The installation was scheduled to coincide with a transformer upgrade. The outage was scheduled for 14 hours and the plant was scheduled to resume production later in the day.

The switchgear feeds raw materials to production and coal to the kilns, so is critical to getting the entire plant back in operation. The retrofit had to be completed in the scheduled time.

The engineering installation team arrived at the site the afternoon prior to the shutdown. The status of the prework was reviewed, the parts were inventoried, and work responsibilities were assigned from the procedures. Work also started on the auxiliary section.

The shutdown work was divided into four tasks: pull and install wiring in the switchgear; install CTs in the transformer transition section; install voltage transformers; and install CTs,

nodes, and wiring in the breaker compartments. Two of the engineers worked in the breaker compartments and two engineers worked on the other items. Segregating the work tasks to separate areas of the switchgear allowed several engineers to work in parallel.

While the initial routing of the wiring in the rear and top of the switchgear was ongoing, the CTs, nodes, and terminal blocks were installed in the breaker compartments. The wiring from the top of the switchgear was then routed to the breaker compartments and terminated, completing the breaker compartment upgrades. Using this parallel, separate section approach maximized the number of people that could work on the gear and minimized the overall time required to complete the tasks. Additionally, work that had to be completed with the power off, primarily in the breaker compartments, remained the focus of the shutdown. For example, the control power wiring was terminated and installed at the switchgear end, while the other end of the wiring at the auxiliary section was not completed. None of the wiring to the auxiliary section was energized, so it could be terminated later. The work division and focusing on the tasks to be completed with the gear shutdown enabled the retrofit team to complete the switchgear work, reassemble the gear, reinstall the breakers, and have the gear prepared to be reenergized in one 14-hour shutdown.

IV. EVALUATION OF RETROFIT VERSUS EQUIPMENT REPLACEMENT

A protection system retrofit can have several distinct advantages over a complete equipment replacement if certain basic electrical requirements are still met with the existing switchgear. In this particular case, the existing switchgear was in excellent working order and was not under-rated in its short circuit or continuous current ratings. The realized advantages of the retrofit versus a complete equipment replacement are as follows:

1) Shorter Shutdown Time: The work to install the retrofit components and get the equipment back on line was accomplished in less than the allotted 14-hour outage.

2) Fewer Trades Involved: The work was focused on the secondary wiring and mounting components. The only work involving primary circuits was the installation of current sensors in the breaker cubicles and potential transformers.

There were no modifications to primary cables or movement of the structure therefore there was no need for riggers or cable installers.

3) Scheduling: The shorter outage and fewer labor resources required for the retrofit were easier to plan and schedule since both were less than that required for a full equipment replacement.

4) Subassemblies: Wire harnesses and panels with system components were subassembled prior to the equipment shutdown. Most of the subassemblies only required mounting and interconnection wiring during the outage.

5) Lower Cost: The retrofit components supplied were a subset of the total material that would have been required for a complete equipment replacement. The retrofit utilized the minimum amount of material and labor to extend the usefulness and functionality of the switchgear and provided the user with many enhanced power system monitoring and diagnostic features for the end user.

6) Future Flexibility: The retrofit protection and monitoring system is software based. Once the basic system compo-

nents are installed, future additions or enhancements to monitoring, control, or protection require only a software change. All hardware remains the same.

V. SYSTEM FUNCTION IN AN ACTUAL OPERATING ENVIRONMENT

The system Design Team monitored the “shadow system” remotely so that any changes in the status of the low voltage breakers or the system components would be recognized via the “system event log”. Some of the breaker nodes were given settings below the actual circuit breaker protective settings so that changes in the circuit loading would create “events” such as an overload trip. Although the actual feeder circuit breakers did not trip, the nodes with the lower current settings was functioning properly by issuing a trip command to a breaker simulator and generating an event listing the current levels that caused the overload trip.

After 5 months in operation, one of the central processors went through a re-boot cycle, which generated an entry in the event log. The system designers were expecting the re-boot due to the software version that the system was running. No other action was taken by the system because the second central processor, which is part of the standard system design, remained on line and continued to provide protection and monitoring for the switchgear.

The utility experienced an outage that was also captured in the event logs. Since the system operates with redundant control power sources and UPS back-up, it was able to record the loss of power to the substation and continue monitoring the status of the breakers and the system components during the outage. Had any of the circuit breakers changed state during the outage, this would have also been recorded in the event log.

At the Whitehall plant, this system is dedicated to one

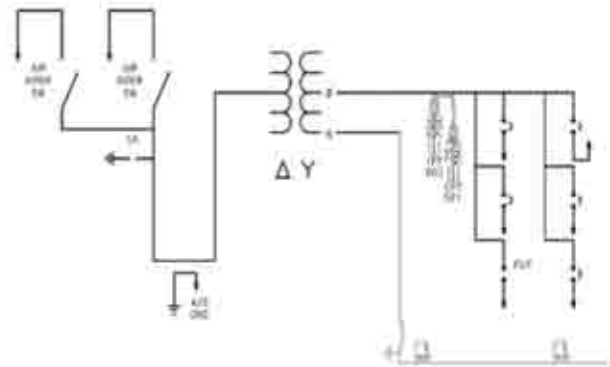


Figure 7. Unit Substation One-Line Diagram

750KVA substation. The real-time data on the “One-Line Diagram” screen illustrated in Figure 7 provides a handy, quick-look snapshot of the status and health of the unit substation. The one-line diagram view is easy for plant personnel to quickly understand since the displayed data is clearly specific and universally recognizable.

Graphic changes showing breaker status such as closed, opened, and tripped immediately attract an operator’s attention when coming into the room. It is not necessary to physically inspect the gear by walking around and looking at each breaker to determine if everything is normal.

Dynamic data, such as ampere load for each breaker, help to determine whether individual plant areas are operating normally. Line voltage, total KVA, total amps, and power factor are critical indicators of overall running conditions.

When an 'event' did occur, it was convenient to quickly switch to an easy-to-identify 'Event Screen' and read a bit of text with a time-stamp to see what happened and when it happened.

VI. CONCLUSIONS

BENEFITS FOR THE END USER:

The features and functionality of a monitoring system applied to a plant's power distribution system is becoming more important. Company budgets allow for fewer people on staff who have traditional "sensing and interpreting" skills tuned to a plant's power pulse. Those responsibilities are being shifted to less-experienced people. Yet power is becoming a more expensive commodity capable of having significant influence on a plant's bottom line. Decisions about power will become a very weighty issue in determining a future, or lack of a future, for process plants.

Power system monitoring, via graphical interface or touch screens, provides a clearer understanding of data that previously required interpretation to those individuals responsible for financial decisions. In corporations today, more people are responsible for making financial decisions that can have a significant business impact. Quick and easy access to power system data is one way to help insure that decisions are made with the best data available.

BENEFITS FOR THE EQUIPMENT SUPPLIER:

Retrofitting existing switchgear with state-of-the-art protection and monitoring equipment is an excellent method of gaining real-world operating experience for a new product. The process provided valuable input to the product design team on items such as:

- Defining the information to be displayed on user screens
- Monitoring component health
- Making the installation process more user-friendly
- Exploring a real-world operating environment with varying load requirements and utility power stability
- Determining user documentation requirements

Execution of protection, monitoring, and control functions from a single, centrally located processor provides a cost-effective alternative to multiple meters, protective relays, and PLC's. The modularity of the system components facilitates retrofitting into existing switchgear. The single processor concept for new or existing low-voltage switchgear provides a powerful protection, data gathering, monitoring, and diagnostic system capable of staying in step with the needs of the power system and the user.

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INSPECTION, MAINTENANCE, AND REBUILDING OPTIONS FOR OLDER CIRCUIT-SWITCHERS

By David Myers, S&C Electric Company and Jon Hilgenkamp, S&C Electric Company

INTRODUCTION

Circuit-switchers provide reliable switching and protection of lines, transformers, reactors, and capacitors at plant switchyards and transmission and distribution substations.

Circuit-switchers were introduced over 40 years ago. Many have been in service for 20 to 30 years and consideration must be given to the options available for ensuring their continued reliable performance - and thus performance of the electric power system.

In addition to the vintage of the device, the type of duty and the number of switching operations determine the extent of maintenance required and the frequency with which it is needed. Circuit-switchers in transformer applications typically have been switched only a few times, if at all. Circuit-switchers in capacitor and reactor applications have typically experienced a higher number of switching operations.

For circuit-switchers more than 30 years old, replacement parts generally are no longer offered. But replacement devices are available that maximize the use of existing structural framework, thus minimizing installation costs.

For circuit-switchers less than 30 years old, replacement parts are typically available, as are a variety of upgrade paths including life-extension options. For circuit-switchers that have been in service 10 to 15 years, only minimal maintenance is necessary to maximize life and ensure continued reliable service.

The inspection, maintenance, and upgrade options which will be discussed not only increase service reliability, but also reduce forced outages and the overall costs associated with the loss of revenue, replacement component inventory, and premium freight charges for immediate shipment of replacement components.

CIRCUIT-SWITCHER TIMELINE

As a preface to the discussion of replacement and upgrade options for circuit-switchers, it is useful to review the history of this device.

Prior to the introduction of circuit-switchers, substation transformers were protected by fuses or oil-type circuit breakers installed with two disconnect switches, for isolating and maintaining the protective device and transformer. A more cost-effective, compact device for switching and protecting substa-

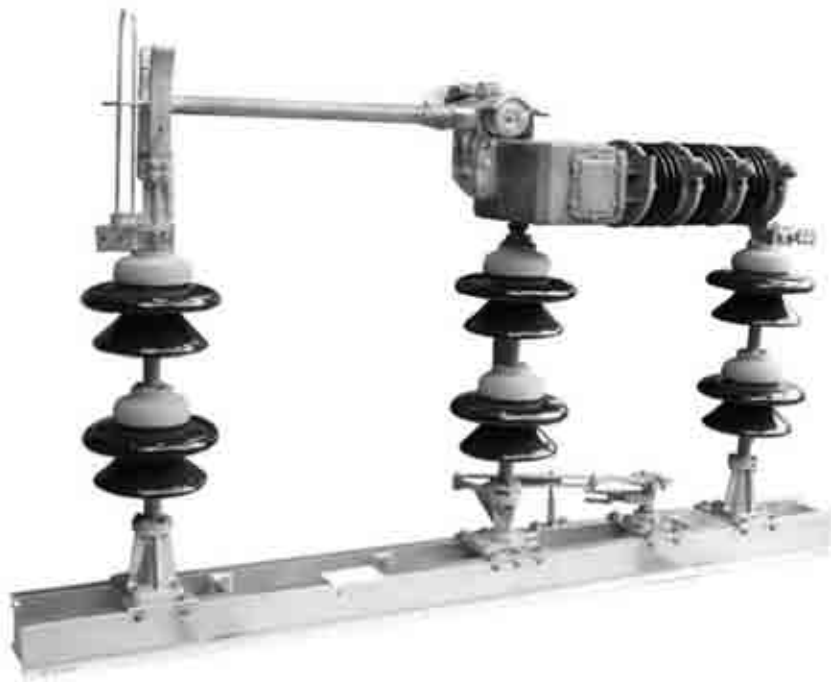


Figure 1. Early 1950s-vintage air-insulated interrupter design circuit-switcher.

tion transformers was desired.

By the late 1950s, a load-break switch with integrated disconnect and air-insulated interrupter was introduced. This device could carry and interrupt 600 A at 138 kV, and was the first step in the creation of the circuit-switcher we know today the industry-standard device for protection of substation transformers.

In 1960, the electric industry was introduced to the next-generation circuit-switcher. It used sulfur-hexafluoride (SF₆) as the insulation medium inside the interrupter. It could carry 1200 A continuous current and was designed to interrupt transformer primary fault current as well.

Through the 1970s, circuit-switcher manufacturers implemented a series of design enhancements to the stored-energy mechanism to achieve proper contact speeds for increased interrupting duty, as well as design improvements to the switch operators. In addition, SF₆ interrupters were introduced capable of withstanding full phase-to-ground voltage in the open position with the isolating disconnect blade in the closed position. This advancement allowed some manufacturers to offer circuit-switchers without an integral disconnect. Also, circuit-switchers were introduced featuring interrupters shipped with only nominal SF₆ gas pressure, to be filled to full pressure at the time of installation (rather than interrupters filled to full



Figure 2. 1960s-vintage SF6-insulated interrupter design circuit-switcher.



Figure 3. 1970s-vintage SF6-insulated interrupter design circuit-switcher.

pressure by the manufacturer and sealed prior to shipment).

In the mid-1980s, circuit-switchers were introduced with higher interrupting capabilities, vertical interrupter configurations, and integrated switch operators.

REPLACEMENT OPTIONS FOR CIRCUIT-SWITCHERS 30 YEARS OR OLDER

In general, replacement components are no longer available from manufacturers for circuit-switchers in this age range. Because of the significant design and performance enhancements effected over the last 30 years, these devices cannot be upgraded to current-design equivalence.

It is in the user's best interest to plan for the change out of these circuit-switchers to provide renewed reliability. For devices installed in critical locations, it would be better to schedule an outage versus experiencing an unforeseen power loss in the event of an unexpected outage. Users should determine the condition of each of their circuit-switchers of this vintage - especially those in critical applications where frequent switching is required and/or where the associated transformer is

considered essential.

Replacement options may include replacing all three pole-units and the switch operator with current-production equipment. Often times, new devices can be selected such that the existing mounting pedestals or structure can be retained, thus minimizing the extent of modifications required to the substation, and reducing installation time and cost. Each application must be carefully reviewed to ensure selection of the proper replacement device.

Circuit-switchers that are removed from service should be carefully dismantled so that key components can be salvaged and cataloged to support the user's remaining inventory.

INSPECTION, MAINTENANCE, AND UPGRADE OPTIONS FOR CIRCUIT-SWITCHERS LESS THAN 30 YEARS OLD

To assure continuing proper performance, these circuit-switchers should be inspected periodically. Manufacturers typically provide guidelines for the frequency of inspections for a particular application, based on the number and magnitude of electrical operations and the number of mechanical operations.

The actual number of open-close operations experienced by a circuit-switcher in service will depend upon the nature of the application. Conditions such as temperature or humidity extremes or highly corrosive or dusty atmospheres can lead to some adjustment to the maintenance schedule.

Each user's own experience will determine whether more frequent inspections are necessary. For transformer protection applications, the maintenance cycle is typically five years, which generally coincides with users' transformer inspection practices. The manufacturer's specific recommendations should be consulted when developing an inspection and maintenance program. For devices less than 30 years old, bolt-for-bolt replacement components are generally available from the manufacturers.

INTERRUPTERS

In the course of their periodic substation visits, users should check the SF6 gas pressure in the circuit-switcher interrupters to verify that gas has not leaked.

For circuit-switchers supplied with interrupters that are filled and sealed by the manufacturer prior to shipment, the inspection procedure involves checking the gas-pressure indicator at the end of each interrupter anytime personnel enters the substation or goes past it. A red target indicates there is a leak. If a red target is visible, arrangements should be made to change out the interrupter. These interrupters cannot be filled in the field but they have demonstrated a very low leak rate.

For circuit-switchers supplied with interrupters that are filled to full pressure at the time of installation, the procedure is somewhat different and depends on whether the device has a common gas system or a fill port for each interrupter. Common gas systems include piping from all three interrupters back to a common fill port. There typically is a gauge to monitor the system pressure. If gas pressure is low, the leak must be located and repaired before the system can be refilled. The techniques used for finding a leak include traditional soap solution, SF6 gas sniffers, and laser detection equipment. For common gas systems, all three interrupters experience the low gas condition. For interrupters that are individually field-filled, a leaking interrupter is typically changed out to eliminate the condition.

Users may wish to check the resistance level of the interrupters during substation visits.

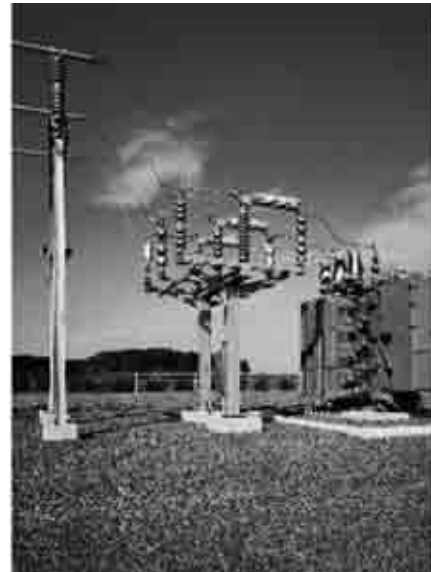


Figure 4. Current-vintage circuit-switchers.

Manufacturers typically provide maximum resistance values for closed interrupters. If the resistance value of an interrupter is higher than the recommended maximum, the interrupter should be replaced.

POWER TRAIN

The circuit-switcher power train typically consists of vertical and interphase operating pipe sections plus gearbox(s), crank arms, rotating bearings, rotating insulator stacks, base linkages, flexible-plate connectors, and shock absorbers (where furnished). Inspection of these components may involve hand-cranking the switch operator to verify that the power train operates freely, without stress or unreasonable external force. All hardware should be checked for tightness. The gearbox should be checked for loose, worn, or broken components. The drive-shaft crank arms should be checked to verify that they toggle in both the open and close directions. Base linkages should be inspected for damaged, worn, loose, or broken components.

Rotating bearings should be inspected to ensure they operate freely and that the rain shields (if required) are installed. The rotating insulator stacks should be inspected for damage and for tightness of hardware.

Experience has shown that rotating bearings, shock absorbers, clevis assemblies, knuckles, pins, and miscellaneous hardware may need to be replaced.

LIVE PARTS

Circuit-switcher live parts consist of the current-carrying components mounted above the insulator stacks. The brain assembly covers should be removed to verify cleanliness, weathertightness, and that all components are intact. With the covers removed, the brain assemblies should be checked and adjusted for proper latch-gap and over-travel. Tripping simultaneity should be adjusted, as required, and the blades should be inspected and adjusted for proper seating. Worn or broken components should be replaced and hardware tightened as necessary.

Live parts should be appropriately lubricated.

Experience has shown that current-carrying and fault-closing jaw contacts, blades and blade pins, and miscellaneous hardware may need to be replaced.

SWITCH OPERATOR COMPONENTS

On circuit-switchers furnished with an integral discon-

nect, the switch operator is decoupled and then manually operated to verify proper operation of the disconnect in both the opening and closing directions. Adjustments should be made accordingly. Electrical components should be checked for proper operation. Brake inspection and adjustment, as well as travel-limit cam adjustment, should be performed. If the circuit-switcher is equipped with optional shunt-trip device, it should be tested to verify proper electrical tripping of all three poles.

Optional relays, timers, and other special features in the switch operator should also be checked at this time. The switch operator should also be checked to verify that all appropriate manufacturer-recommended field modifications have been performed. The circuit-switcher should be operated electrically

with a meter connected across the incoming control source to verify appropriate supply requirements.

Experience has shown that the motor, brake assembly, contactors, and switches may need to be replaced.

CONCLUSIONS

Inspection, maintenance, and upgrade options are available to enhance the reliability of circuit-switchers that have been in service up to 30 years. It is possible to return them to like new state by replacement of worn components.

This approach can provide considerable savings in engineering, equipment, material, and construction labor costs, as well as downtime compared to installing a new device.

PROTECTION, CONTROL, RELIABILITY AND DIAGNOSTIC IMPROVEMENTS VIA SINGLE-PROCESSOR CONTROL OF CIRCUIT BREAKERS IN LOW-VOLTAGE SWITCHGEAR

By Marcelo E. Valdes, PE, IEEE Member, Indrajit Purkayastha IEEE Member, and Tom Papallo, General Electric Company

Abstract – Protection of low-voltage circuits has been a key area of innovation and continuous improvement since the invention of electricity. In the current state of the art, fuses and circuit breakers protect individual circuits. These devices, in turn, use many different kinds of trip mechanisms, operating in various modes that require sensing the current that travels through the circuits. However, these devices, largely, operate separately and independently from each other.

Communication networks and external relays are sometimes used to enhance selectivity and provide better protection than the independent over-current devices can provide. In this paper, the authors explore a protection-and-control architecture based on a single processor that provides all the protection and control functions for a lineup of low-voltage switchgear. How this method of protection changes the paradigm from individual circuit protection to system protection, while cost-effectively and significantly increasing system reliability and protection, is discussed.

I. INTRODUCTION TO THE SINGLE-PROCESSOR CONCEPT

A. BACKGROUND

Communication networks are becoming more common in today's switchgear. They provide the important functions of gathering and reporting information from individual devices, such as trip units, meters, and protective relays. In low-voltage systems, communications often provide supervisory logic, such as load-shedding schemes or reporting of basic electrical information and event status to a central control computer.

A typical architecture with system-wide communications employs a master-slave polling technique. In this type of network, a supervisory computer sends instructions or requests for information to one of the slave devices. The slave device then responds as defined by the network protocol. This implementation has a variable latency, due to such factors as the amount of information requested from each device, the response time of the device, and the communication delay time specified by the protocol. This variable latency limits this type of network to supervisory functions and information gathering. To improve protection, fast, reliable, and deterministic communication is needed.

A varying number of devices and the variable length of each message creates a situation in which response times after events are difficult to predict and can be relatively slow.

Techniques such as interrupts can give a higher priority to information that a sensing device has judged as particularly important. However, this does not lead to a deterministic response with predictable performance. Faster networks, including Ethernet, may provide very fast communication rates, but the collision-detection multiple-access (CSMA/CD) protocols typically employed do not provide predictable, deterministic response times.

Protocols specifically designed for machine and device control, commonly known as Industrial Control Networks or Control Access Networks (CAN), such as Control INET, Profibus, DeviceNET, FIP, Interbus, SDS, ASI, Seriplex, CANOpen, and LON Works were considered. Some of these offered promising capabilities with respect to data rate, reliability, and scalability. However, none offered the optimum combination of capabilities needed to provide fast, reliable, and deterministic communication. Specific derivatives based on the Ethernet standard, such as Ethernet/IP, Profinet, and Modbus/TCP, were also considered by the designers.

However, the application layers of these Ethernet derivatives are not compatible with the requirements of the application.

B. THE NEW CONCEPT

The concept discussed in this paper uses a methodology different from that of all other electrical equipment systems to date. Communication is based on the capabilities of Ethernet, while removing the time variation introduced by CSMA/DA protocols. Communication is structured to yield fixed latency and sub-cycle transmission times between a central processor and all the devices in the system. Fast communication and fixed latency are key enablers for using a communication network to perform critical control, monitoring, and protection functions.

A second distinction between this concept and traditional communications found in electrical equipment is in the types of information carried on the network. Rather than processed summary information captured, created, and stored by devices such as trip units, meters, or relays, the actual raw parametric or discrete electrical data and device physical status are carried on the network. The data sent from the devices to the central processor are the actual voltages, currents, and device status. As a result, any microprocessor on the network has complete system-wide data with which to make decisions. It can operate any

or all devices on the network based on information derived from as many devices as the control and protection algorithms require.

The architecture discussed here is centralized, with one microprocessor responsible for all system functions. Alternate architectures, such as distributed and semi-distributed, were considered, but the central processor architecture had the best performance. Fig. 1 shows the centralized architecture applied to a typical lineup of low-voltage switchgear, with a central computer performing the control and protection functions and each breaker acting as a node on the network.

The key advantage of this architecture is that the single processor has all the information from all nodes simultaneously. Thus, protection and control schemes can be designed that consider the value of electrical signals, such as current magnitude and phase angle, at one or all circuit breakers in the system with equal ease. This allows the implementation of circuit-specific zone-protection functions as easily as a simple over-current function at a single circuit breaker.

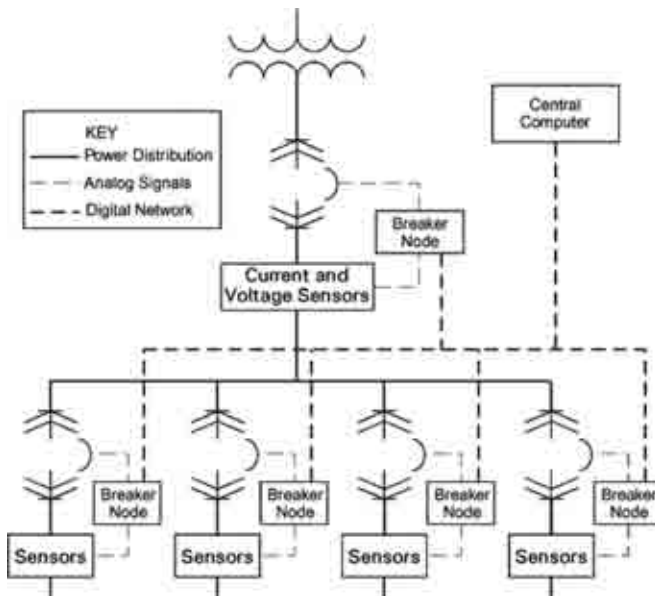


Fig. 1. Centralized control architecture

This architecture yields fixed latency that includes scheduled communications, a fixed message length, full duplex operating mode, and a protocol that time slots each message on the network, so that all messages arrive and are handled by the central processor well within a single cycle.

This design also schedules all the communication and the programs within the various microprocessors to allow synchronization of information from all devices within a 6- μ s window.

The use of a single processor raises concerns about reliability and a single point of failure that could compromise the protection of all devices within a system. These concerns may be addressed via various methods. The use of hardened industrial electronic components increases the reliability of the individual subsystems. The use of redundant processors can provide increased reliability via redundancy. The electronics at any one circuit breaker node may also be expanded to include back-up protection functions similar to those of a traditional electronic trip. In addition, self-diagnostic algorithms can be employed to

detect major or minor subsystem or component failures and make appropriate adjustments in algorithms to structure the protection into another combination of functions that provide adequate protection. For example, upon loss of a sensor at a main circuit breaker, the over-current functions of that breaker could be directed to function with the sum of the current signals of the entire load-side feeder breakers, making appropriate adjustments for the errors that method may introduce. In a traditional system, loss of a sensor at a circuit breaker inhibits all over-current protection at that circuit breaker.

C. SPECIFIC IMPLEMENTATION FOR LOW-VOLTAGE SWITCHGEAR

Recent advances in processing power and communications bandwidth allow use of such a control system in electrical equipment not only for monitoring, but also for relaying, metering, control, and over-current and short-circuit protection. Each breaker node can digitize the analog signals for each phase at a rate of 32 to 128 samples per 60-Hz cycle, comparable to the rates used in modern trip units.

These samples can then be transmitted individually or in groups to the central computer in sub-cycle or even submillisecond periods. Network capacities of 100 megabits per second or more enable control of systems of 24 or more breakers by a single computer.

A system of 24 breakers sampling three phase currents, one neutral current, and three voltages at 64 samples per cycle generates data at rates of approximately 10 megabits per second. Not only must the network have the capacity to carry the data, the central computer has to process the data, perform the necessary protection, relaying, and control calculations, then respond to the breaker node before the next transmission. This significant data throughput and processing is possible today using commercially available high-capacity networks and modern microprocessors with computation ability of 1500 MIPS (million instructions per second).

Technological advances in the last five years make using this architecture for switchgear protection feasible.

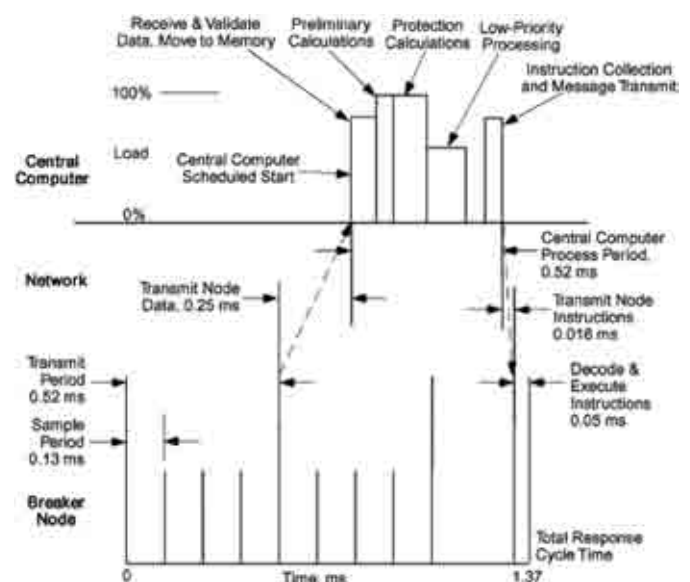


Fig. 2. System processing time line

Fig. 2 shows a timeline in cycles for a typical centralized system. The process is started at the node. Each node is scheduled to sample its analog signals at a prescribed rate; 128 samples per cycle in this example. In addition to the data sampling, the individual signals are filtered. Sampling continues at the prescribed period until four samples are collected, at which point the node groups them and transmits this packet to the central computer. The central computer operates on a receive-process-transmit sequence with the same period as the sample transmit. Data from all breaker nodes are received, validated, moved to memory, and preliminary calculations, such as squaring the current, are then performed. Protection-algorithm calculations, as well as metering and other critical processing and logic, are performed. After the calculations are completed, all instructions resulting from the multiple algorithms for the breakers are collected and an instruction message is constructed. This message is then sent to all nodes. The processing sequence is completed before the next transmission from the breaker nodes arrives at the central processor.

Any additional microprocessor capacity can be used to perform lower-priority, non-critical tasks, such as updating kWh and demand logs. The central computer is now ready to receive the next set of data and continue its protection functions. For functions requiring longer data intervals, previous data sample sets are retained and the accumulators are updated with the new data. Using this technique, instantaneous, short-time, and long-time trip functions can be performed well within the times provided by modern integral electronic trips.

When the node receives the information packet, the node decodes it and executes any instructions for changing the circuit breaker state. The timing of this is shown in Fig. 2. The first interval of 0.52 ms is used for data acquisition of four data samples. Data from 24 breaker nodes represents 23,870 bits.

Operating at 100 Mbps (megabits per second) the network requires 0.25ms to transmit all node data to the central computer. All algorithms take multiple samples to improve noise rejection. The second 0.52-ms interval is the receive-process-transmit cycle of the central computer. The communication to the breaker node, which is a much smaller message, requires 0.016 ms to reach the nodes. Decoding the message, processing at the node, and activating the analog outputs takes 0.05 ms. Thus, the entire sequence from the initiation of an event to breaker-node response requires 1.37 ms, allowing the sequence to occur 12 times per cycle.

The processing cycle time can be accelerated or decelerated for the application's needs by adjusting the sample period and the number of samples per transmission. This 1.37 ms is the system latency, but does not affect the system synchronization. All of the sample conversions start at the same time. Each message is sequenced to maintain its relationship to the correct time before it is used in a vector calculation. The central computer continuously maintains the data's correct sampling sequence. The order or delays inherent to the calculations do not alter or have an effect on the synchronization of the data to real time.

The advantages of such a system-wide approach may be most appreciated when considering zone-protection functions that require information from multiple points in the system simultaneously. Each node is simultaneously sampling contemporary data. The central computer can combine the information from various nodes and use it to perform differential-zone functions, such as multiple-source ground fault, zone-selective interlock, and bus-differential protection.

Furthermore, in addition to analog electrical information, device status is included in the network data. Knowing the status of all devices, the central computer can determine the system state. Combining the system state with known electrical parameters at each active node creates the possibility of dynamic reconfiguration of the protection functions, according to power flow. This enables dynamic zone protection, with protective settings based on the configuration and loads of the system.

D. BACKGROUND AND CURRENT STATE OF THE ART IN CIRCUIT PROTECTION

The art and science of coordinating circuit breakers has advanced only incrementally since the first thermal-magnetic breakers and dashpot-operated trip mechanisms were introduced. Bimetallic strips and magnetic forces are still employed in most circuit breakers today. The introduction of electronic trips in the 1960s and of digital trips in the late 1970s has led to the replacement of magnetic-dashpot trip devices and provided an alternative to thermal-magnetic trips.

These newer trip mechanisms improved the range and flexibility of settings available with individual circuit breakers. Later developments allowed circuit breakers to signal each other in an attempt to achieve coordinated operation.

However, the basic methodology for selectively coordinating circuit breakers has not significantly improved.

Choosing the types of circuit breakers and trip mechanisms and the settings for those trips has always involved trying to find the optimum compromise between system reliability and protection, while operating under investment and space limitations. Better selectivity can be achieved at the cost of lowering the level of protection, while better protection is achieved at the

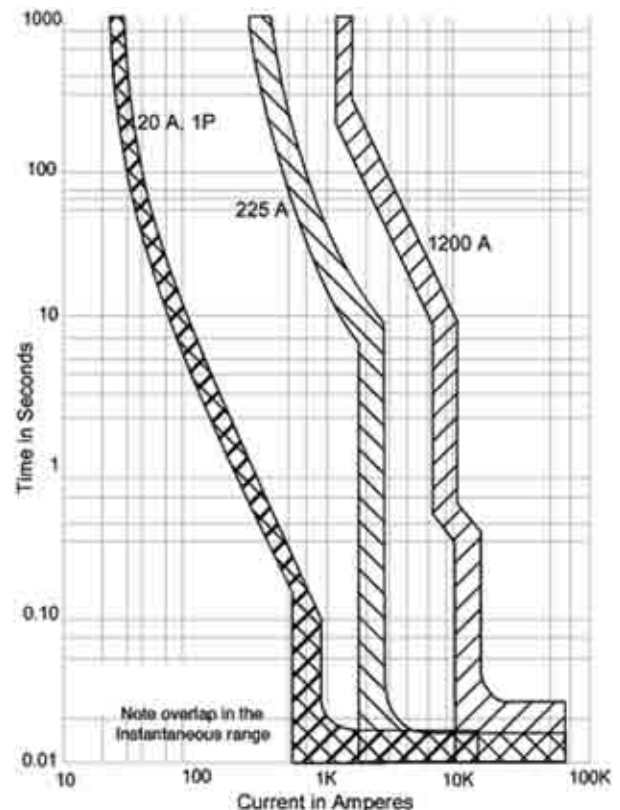


Fig. 3. Time-current curve plot for molded-case breakers

cost of incurring a greater risk of unselective operation or nuisance trips. A good engineer strove to achieve the best compromise satisfying the needs of the system's mission, while keeping within the budget and size constraints.

The most common way to selectively coordinate protective devices is to simply choose devices whose inverse-time characteristics allow the device closest to a fault to detect the fault and initiate a trip, thus interrupting and isolating the fault before a larger line-side device commits to tripping. With thermal-magnetic devices, it is a simple exercise of laying out the trip-time curves so that they do not overlap, also known as nesting the time-current curves.

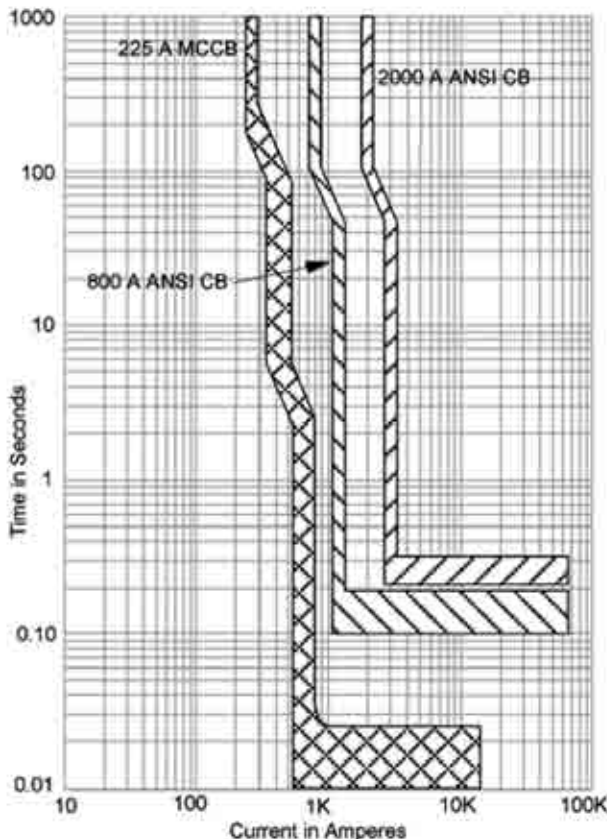


Fig. 4. Time-current curve plot for ANSI circuit breakers

When molded-case circuit breakers employing magnetic trips are used, the instantaneous or magnetic parts of the curves usually overlap for fault-current values above the highest setting of the line-side device, as shown in Fig. 3. This can result in high-value faults causing the tripping of multiple breakers simultaneously. This provides protection but clearly sacrifices system selectivity and reliability. Electronic-trip breakers allow more careful shaping of the curves, usually achieving a better compromise between protection and selectivity.

Newer-design circuit breakers with electronic trips allow the instantaneous settings to be as high as 10 to 15 times the frame or sensor rating of the circuit breaker. However, a 4000-A circuit breaker set at 10X only reaches a nominal setting of 40 000 A, which may be well below short-circuit currents available in a modern power-distribution system. This can result in unselective tripping for high-value faults. Low-voltage power circuit

breakers can be used when the lack of selectivity caused by instantaneous protection is undesirable.

The ability of these circuit breakers to delay tripping for up to 30 cycles allows the full coordination of multiple layers of devices within a system, as illustrated in Fig. 4.

Although this achieves much better selectivity, it does so at the cost of sacrificing protection of the conductors and equipment. A further drawback of this method is that a lineside device with several load-side devices under it can only be set as fast as the slowest load-side device and as sensitive as its sensors and zone of protection allow. This means that the line-side device may not be providing the best level of protection for its zone and that it doesn't act as a true backup for all the load-side devices.

E. GROUND-FAULT PROTECTION

Ground-fault protection presents different challenges and opportunities for circuit protection. A well-understood property of systems in which voltages to ground exceed 150 V is the "arcing ground fault", in which a current conducted through ionized gas can sustain itself indefinitely. The current of an arcing ground fault can be intermittent, initiate a larger phase-to-phase fault, or simply last and cause localized damage. A significant improvement with electronic trips is the ease with which integral ground-fault protection can be provided.

Electronic circuit breaker trips typically provide arcing-fault protection by calculating a vector sum of the currents through each conductor in the circuit and comparing the resultant to zero. A value larger than zero implies that current is being improperly conducted to ground. Unfortunately, the inaccuracies of current transformers, charging currents, normal leakage, and the intermittent nature of the currents do not allow this method to be as accurate as one would like.

Nevertheless, this method can be used to detect ground currents significantly below the phase currents of the devices.

This provides valuable protection from low-current arcing ground faults characteristic of 480/277-V systems. Groundfault protection systems work well, but often increase the cost and complexity of a protection system.

Various schemes have been used to improve traditional selectivity and protection, most depending on some level of communication among protective devices. The most common scheme used in low-voltage systems is zone interlocking which is used for ground-fault protection and phase protection in the short-time (100–500 ms) range. If a fault is detected by a load-side device and the device can communicate that fact to the line-side device quickly enough, the line-side device is delayed to allow the load-side device to detect the fault, react, and trip within a set delay time. When the line-side device does not get a blocking signal from any of its load-side devices and it senses a fault, it can react with a faster setting based on the knowledge that the fault is in its zone of protection and not that of one of its load-side devices.

A similar capability is offered in medium-voltage relays, operating within the instantaneous range of the relay. In medium-voltage applications this is usually referred to as "blocking".

A weakness of these methods is that the line-side device does not know which load-side device is sending the blocking signal. Therefore, its fault sensitivity or delay cannot be customized to the specific circuit experiencing the fault. Thus, the line-side device must be set to accommodate the largest fault magnitude and longest time delay of all its load-side devices. This represents the most significant compromise between selec-

tivity and protection with which the system designer must contend.

F. DIFFERENTIAL PROTECTION

Another form of protection involving signals from different points within the system is differential protection. With this scheme, all the currents entering a zone are measured and compared with all the currents properly leaving the zone.

When the total currents add to zero, all is well, but if the currents entering are greater than the currents exiting, the difference indicates a fault within the zone, as illustrated in Fig. 5. This method is most commonly applied with bus differential or transformer-differential relays. This involves the use of separate specialized relays and the proper interconnection of current transformers in every phase around a zone. When multiple zones are used, the locations of the transformers must be carefully thought out so that zones overlap without leaving unprotected sections within the distribution system. The settings of the relays cannot be so sensitive that they are fooled by the multiple inaccuracies and the saturation characteristics of the various transformers.

Again, to prevent nuisance trips and overprotection, some level of protection has to be sacrificed. In addition, the cost and complexity of this scheme do not often allow it to be employed in low-voltage power-distribution systems.

II. ADVANCED SYSTEM PROTECTION ENABLED BY THE NEW SINGLE-PROCESSOR CONCEPT

This new system differs from current state-of-the-art, low-voltage protection schemes in one critical way. The new system brings all information from all points in the equipment to a single processor with the capability to analyze and control all devices in the system fast enough to support all necessary protection modes, including short-circuit trips of multiple devices simultaneously. The single processor is aware of all important signal values with 6- μ s resolution. This differs from today's systems which consist of individual protective devices with only minor communication among them. This one distinction significantly broadens the protective capability that the system can achieve economically and reliably.

A. INVERSE TIME-CURRENT CURVES, THE SIMPLEST FORM OF PROTECTION

The simplest form of over-current protection is the inverse time-current characteristics and fixed time delays that can be assigned to each circuit breaker in the system. Even when using these simple inverse time-current time bands to achieve selectivity, the concept system is able to display a significant edge over conventional independent multiple-breaker systems. In a typical main and multiple-feeder system, the main breaker is set to handle the maximum current that the bus may carry, or the sum of the currents of each of the feeders. In the single-processor system, the main would be set likewise with respect to the protection requirements of the main bus. However, the main breaker may also be set with a current setting equal to that of each of the feeder breakers and a time characteristic that allows it to provide backup protection to each individual feeder at that feeder's setting.

The processor would simultaneously monitor the current at the main bus and each of the branch circuits, reacting to an undesirable current at any point. This provides each branch circuit with secondary backup protection optimally set to supplement the primary protection with no compromise needed to

achieve selectivity or to allow the bus current to flow unimpeded.

B. ZONE ENHANCEMENT FOR THE SIMPLEST FORM OF PROTECTION

In the concept system, the trip characteristics of the breakers can be set as they would be in a traditional system, but zone implementations can have a substantial advantage.

Traditional zone-selective interlock improves this situation by shortening the main delay, but typically resets the main delay to preset values regardless of which feeder is experiencing the fault.

With the single-processor solution, a zone function replaces the traditional time-current and fixed-delay protection while achieving both selectivity and tight backup protection. The feeder breakers (load-side) are set as before to serve their loads reliably, but the mains and ties (line-side) dynamically set their delay and current settings to best fit each feeder when that feeder circuit experiences a fault.

Consider the example, illustrated in Fig. 5 and Table I, of a double-ended substation, with 4000-A mains, feeding several feeder breakers on either side of a 3200-A tie circuit breaker.

For the purposes of this example let us consider a 1600-A feeder on the left bus, Feeder-1, directly fed by Main-1, and an 800-A feeder on the right bus, Feeder-2, fed by Main-2.

The Tie is also closed. Typical settings for such a system may have the 800-A feeder breaker set at 2X short-time pickup and a time delay of 60 ms to clear the instantaneous trip of load-side molded-case circuit breakers. The 1600-A feeder could be set at 2X and a time band of 100 ms. Traditionally, the Tie would have a longer delay than the slowest feeder, 200 ms in this case, and the mains would also require a delay slower than that of the tie circuit breaker, 300 ms. With the new concept, the tie and main trip-time curves need not be defined in this manner; the zone function establishes their optimum curves when the fault occurs.

If a fault of 3200 A occurs on Feeder-1, the feeder's protection recognizes this fault and should trip Feeder-1 after a 100-ms delay. Simultaneously, the zone routine recognizes this feeder fault and knows that its location in the system is outside the tie's and mains' zones of protection. The algorithm sets the short-time delay of the Tie and Main-1 to 200 ms and of Main-2 to 300 ms. The Tie and Main-1 will be in short-time pickup mode because of the 3200-A fault current of the feeder, but not for their own currents. When the feeder opens normally, the current drops, the zone function stops timing out, and selectivity is maintained. If the feeder does not clear, the Tie and Main-1 trip at 200 ms to back up the feeder and Main-2 could trip at 300 ms to back up the Tie, if required.

If a fault occurs on Feeder-2, the zone function expects the feeder to clear after a delay of 60 ms. Delays at the Tie and Main-2 are set to 160 ms and Main-1 is set to 260 ms. In this case, selectivity is also achieved. Backup protection is as tight as the circuit breakers allow. In response to the 1600-A fault and the 3200-A fault, the delays of Main-1 and Main-2 are reduced by 180 ms and 220 ms, respectively. It is important to note that, in both these cases, the determination of a fault is based on the feeder's settings and the sensors. In a traditional system, the sensing of a fault at the tie or main is based on the settings at those trips and the current flowing through the respective circuit breakers. If the current magnitude is not sufficient to be recognized as a fault the trip units will not initiate a trip and hence provide no back-up function.

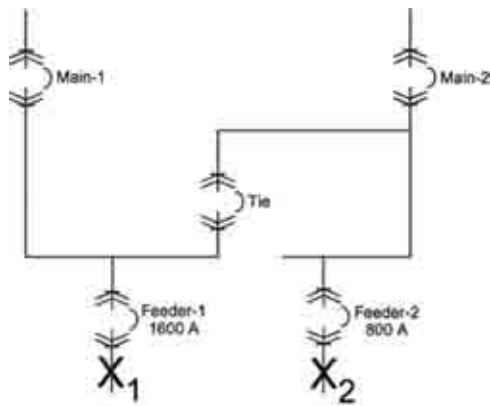


Fig. 5. Example system

TABLE I.
SETTINGS FOR EXAMPLE SYSTEM

Device	Setting	Time			Current		
		Nominal Setting	Dynamic (Backup Setting 1)	Dynamic (Backup Setting 2)	Nominal Setting	Dynamic (Backup Setting 1)	Dynamic (Backup Setting 2)
Main-1	4000 A	380 ms	200 ms	260 ms	8000 A	3200 A	1600 A
Main-2	4000 A	380 ms	300 ms	160 ms	8000 A	3200 A	1600 A
Tie	3200 A	220 ms	200 ms	160 ms	6400 A	3200 A	1600 A
Fdr-1	1600 A	100 ms	—	—	3200 A	—	—
Fdr-2	800 A	60 ms	—	—	1600 A	—	—

Further, if the fault occurs in the switchgear, the main breaker detects the fault but no feeders experience a fault.

The single-processor system is also able to discriminate this situation and can issue a trip command to the proper line-side device, at whatever time delay is programmed, to within one-half cycle. Zone interlocking for the single-processor system is not limited to the short-time delay bands normally associated with circuit breakers. Line-side devices are also aware when a load-side device should be in its instantaneous tripping range and can provide tight backup protection in that situation, as well as for the short-time fault described above.

As can be readily seen, this allows all line-side devices controlled by the single processor to provide perfectly coordinated backup, regardless of the size ratio between the line-side devices and any of the feeder load-side devices.

There are no additional margins of safety or unnecessary time delays needed to allow the system to operate selectively and provide protection to the mechanical limits of the devices used.

This scenario also applies within the short-circuit ranges of the devices in the system. When the processor senses a fault within the short-circuit range of any load-side device, the next line-side device is ready to operate immediately if the processor senses that the load-side device is not clearing the fault, even if the fault may not be in the instantaneous range assigned to the line-side device. This form of backup protection could save many cycles of fault current when a feeder fails to open or if the fault occurs in the switchgear, without sacrificing selectivity.

C. BUS-DIFFERENTIAL PROTECTION

The earlier description of bus-differential protection

showed it to be a good way to identify faults within the bus of a low-voltage switchgear lineup. However, this type of protection normally requires dedicated current transformers, relays, and wiring, making it too complex and expensive for use on most low-voltage systems. However, this is not the case for the concept single-processor system. Since the processor has the values and vector directions of all the currents at the same time, it is able to measure and detect any current anomaly within the system and can detect an inappropriate lack of current flowing from the feeder. Once the processor has determined that a fault current is originating at the bus, the trip command can be issued to the appropriate circuit breaker immediately. The fault current only lasts long enough to be detected and the time to extinguish is only limited by the mechanical delays of the switching devices. There is no need for the protective algorithms to create any artificial time delays.

Bus-differential protection enhances in-gear fault protection for current levels that traditional protection does not typically cover. Zone-selective interlock reduces the phase-to-phase fault duration for in-gear faults, but only when the magnitude of the fault exceeds the short-time pickup of the main breaker, which can be as high as 36 000 A for a 4000-A breaker.

Ground-fault protection operates at much lower currents, as low as 800 A for the same 4000-A breaker, but only provides phase-to-ground protection. Bus-differential protection provides sensitivity in the range of arcing faults for phase-to-phase faults. The only limitation is the combined accuracy of the current transformers or sensors used in the system. The combination of bus-differential protection and zone-selective interlock in conjunction with ground-fault protection presents the opportunity to provide comprehensive arcing-fault protection in switchgear. Ground-fault and bus-differential protection provide phase-to-ground and phase-to-phase protection with sensitive detection levels, able to detect arcing faults. Zone-selective interlocking provides short clearing times at elevated fault magnitudes. All of these techniques, by detecting lower currents or by reducing clearing times, lower the total energy of an arcing fault within the switchgear.

Fig. 6 shows potential timing and current pickups for overcurrent protection and bus-differential protection on a 2000-A circuit breaker. For a circuit breaker set at a nominal 2000 A, the over-current pickup may start at 2000 A. However, the differential pickup may start as low as 40 A. The current-to-time relationship for the over-current function would follow the typical inverse-time characteristic that includes both long-time and short time delays. However, the differential protection would only need to introduce the minimal delays needed to account for synchronization or sensor timing errors, plus the additional computational time needed to prevent magnitude errors. Use of low-power current transformers with well-known, predictable characteristics can decrease timing errors to well under a millisecond, which can be accounted for within the protective algorithms. The concept system can detect a differential fault in as little as 24 milliseconds.

D. GROUND-FAULT PROTECTION

Arcing ground-fault protection in today's devices also uses time-delay bands and zone interlocking. In the single-processor system, all of the enhancements described for over-

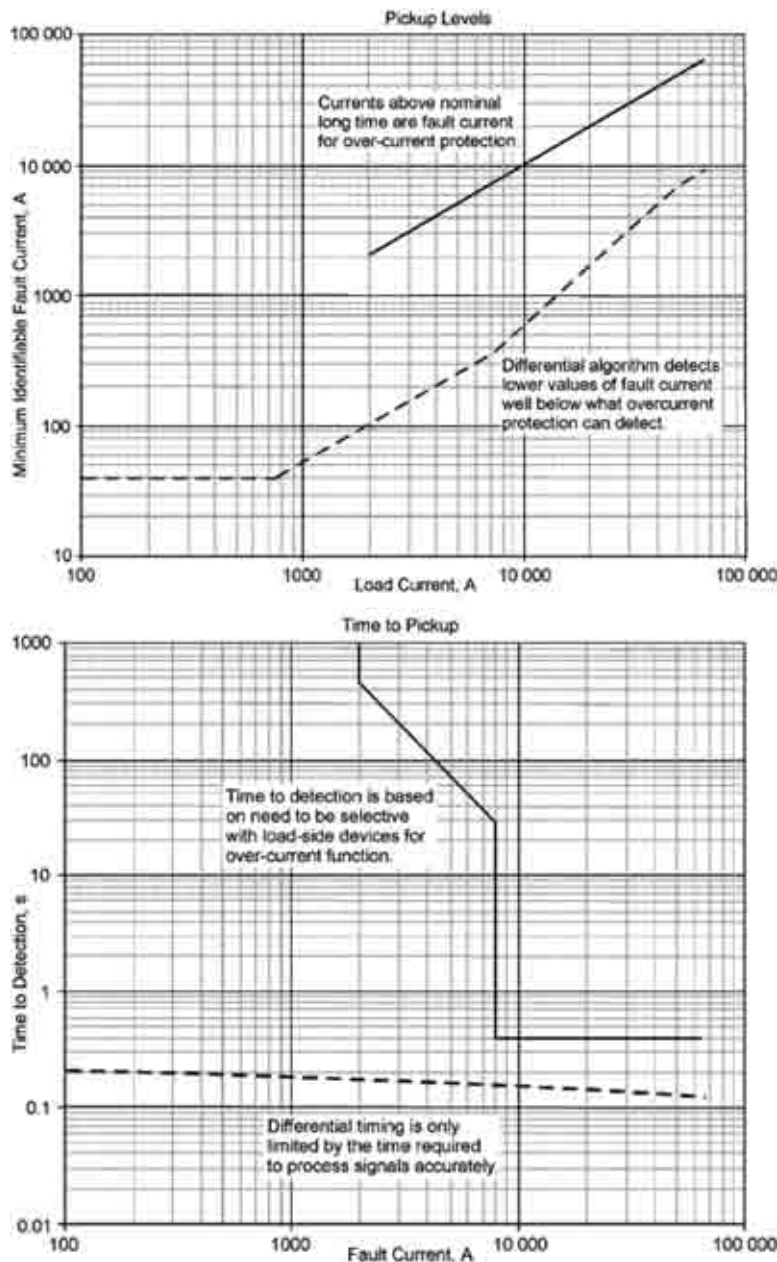


Fig. 6. Differential Protection Timing

current protection are also available for ground-fault protection. Load-side to line-side device curves can be dynamically coupled for immediate backup protection with no unnecessary delay of line-side devices at any detectable fault magnitude. Zone protection allows line-side devices to operate at maximum speed once a fault is detected in the zone. And the differential algorithms can capture a low-current arcing fault whether it is a phase-to-ground or phase-to-phase fault.

E. SIMULTANEOUS MULTIMODE PROTECTION

The four modes of protection described so far can be understood as four sets of functions to facilitate understanding of how protection is achieved. However, unlike traditional protective devices, each mode of protection is not provided by a different device or different sensor. In the concept single-processor system, only one processor is needed for the system's protective

functions and only one set of sensors sized for the feeder-circuit current is needed at each circuit breaker.

The single-processor system is able to accommodate more than one processor to provide redundant computing power and is even able to accommodate protective functions at the device nodes for purely redundant backup. However, no protective functions require any additional hardware or wiring beyond the minimum required for any single mode of protection.

F. MONITORING AND EVENT CAPTURE

In state-of-the-art conventional systems, each circuit breaker trip mechanism and meter operates independently.

Each device independently captures all data, such as current magnitude, waveforms, or voltages. For multiple devices to capture information simultaneously, an event has to trigger the devices to do so, or a central CPU has to issue a capture command to each device. Typically, available data are limited to current values at trip mechanisms that have opened or indicator flags at those same trips. More advanced trip mechanisms may be able to provide waveform capture with some cycles of information pre- and post-event. Devices that do not sense the event capture no data. When the device closest to the fault does not operate and the line-side device acts as backup, no load-side device information may be available.

A central CPU can issue commands to multiple devices to capture information or the CPU itself can store information from multiple devices when it knows an event has occurred.

However, time stamping of such information is not typically done with sub-cycle accuracy. Delays of many milliseconds or even seconds are possible. Resolution can be improved by having the central CPU broadcast synchronization pulses; however, even when that is done, resolution may still be measured in milliseconds.

The single-processor concept system does not share any of these limitations. The time resolution of all information processed is under 6 μ s. The deterministic sequencing of information acquisition by the processor forces information to be continuously synchronized. In a system employing 128 samples per cycle, every sample is synchronized with every other sample in the system.

In addition, during all calculations at the single processor, the information from all the devices is known for the present and for as far back as the algorithm chooses to keep it, at the maximum data-sampling rate. Thus, any event can be programmed to generate the capture and storage of any subset of information desired, including all current magnitudes and phase angles and all setting values and device states.

The captured information can extend backward and forward several cycles. The only limitations are those set by the algorithm and the available memory.

Just as protection can be expanded from the limitations of an individual device to a system-wide perspective, event capture and electrical measurement can now be moved from the view available to one device at one point in the system to the expanded panorama seen from an omniscient central point.

III. THE VALUE OF SYSTEM-WIDE INFORMATION CAPTURE, WITH AN EXAMPLE

Consider a system with a double-ended substation designed with 2000-A mains and tie shown in Figure 7. The designer of the system chose not to set up the feeder circuit breakers with ground-fault detection. However, according to code the mains were set up with ground-fault detection and tripping set to nominal values of 0.2X, 400 A, and minimum time delay.

During operation of the system with the tie open, the single processor measures 2000 A on breaker Main-2 with a slight current imbalance. The single-processor also measures 1600 A with a smaller imbalance on Main-1. The single processor is capable of performing the ground-fault protection for these breakers because synchronized current from the tie breaker is also available to the processor, capturing the portion of the neutral current caused by the imbalance that is conducted by the tie neutral bus.

During operation, feeder R-2 is conducting 800 A of load

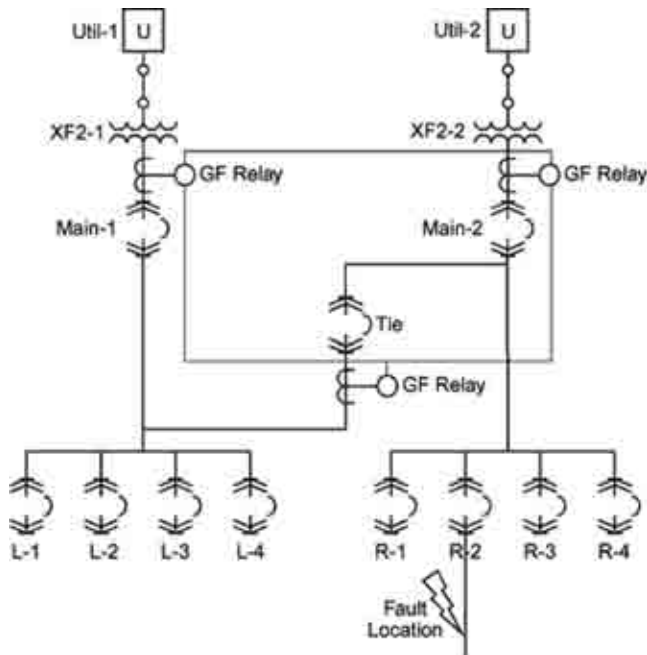


Fig. 7. Double-ended substation example system

current when a 550-A fault occurs between phase A and ground. This fault is immediately detected by the ground-fault relay function, which times to the set delay and trips breaker Main-2. Fig. 8 shows the waveform captured by the relay. If a traditional ground-fault relay with waveform capture were used, this would be the full extent of available diagnostic information. It verifies that a ground fault indeed occurred, but little else.

With the single-processor concept, the single processor is continuously receiving synchronized waveform data from all breaker nodes. Hence, when the ground-fault relay trip occurs, the single processor can store all waveforms for all breaker nodes, even the breaker nodes that did not trip as a result of the fault. Additionally, using a high-speed 32- or 64-bit micro-processor with a large addressable memory space allows several seconds of waveform capture with pre-triggering, rather than just the few cycles available with today's devices.

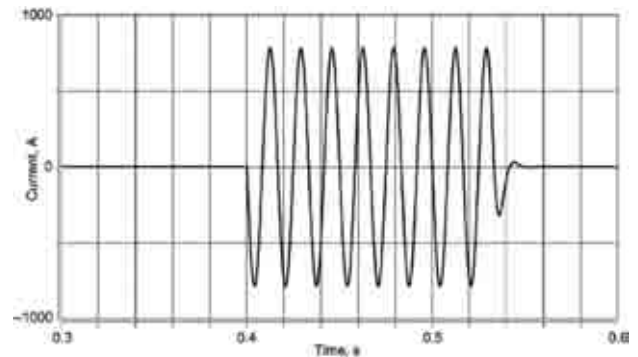


Fig. 8. Waveform captured by example ground-fault relay.

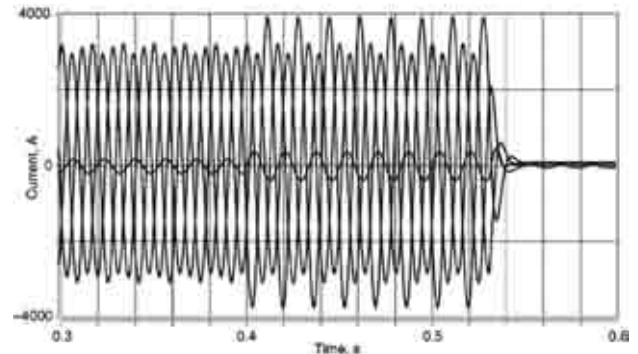


Fig. 9. Captured waveform from Main-2.

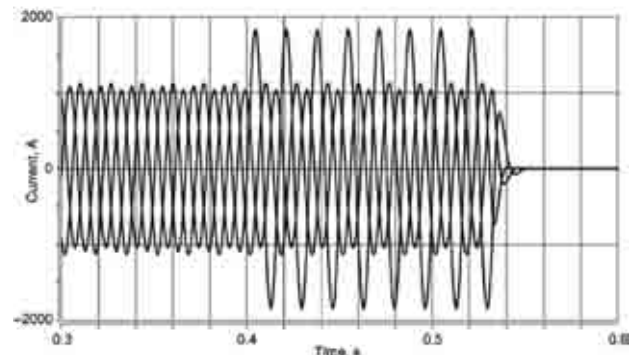


Fig. 10. Captured waveform from feeder R-2

The value of the system-wide waveform capture for fault diagnostics is immediately obvious by inspection of the captured waveforms for Main-2 and feeder R-2, Figs. 9 and 10, respectively. Inspection of the Main-2 waveform shows that the Main-2 node detected the incremental 550 A on phase A of the main bus. That is the same 550-A current that can be seen on feeder R-2, on that bus. This allows the system to pinpoint the exact location of the fault current to the phase and feeder location, even though the feeder circuit breaker never tripped. The system operator can now open the suspect feeder breaker and re-energize the main bus to rapidly restore service to the balance of the system.

IV. RELIABILITY CONSIDERATIONS

The single processor system, at first glance, raises concerns over the reliability implications of entrusting the protection functions and control function of several circuit breakers to

a single computer and communication bus. However, this very capability can result in an enhancement of the over all reliability of the system. The ability to concentrate all the required tasks and information processing into a single CPU and communication bus also allows the incorporation of redundancy quite simply. In addition, the redundancy can allow one component in the system to monitor the health of another. Furthermore, the reliance on serial communication and very few components for sensing, communications and information processing provides a significant reduction in wiring and terminations, eliminating the risk associated with that aspect of switchgear construction and ownership.

A. REDUNDANCY

The system architecture for the Single-Processor Concept easily accommodates redundancy for all potential single points of failure.

The architecture described uses redundant CPU, commu-

of multi point protection algorithms and metering. It has no effect on basic over current functions.

The second class of devices that are not redundant are those associated with only one circuit breaker. Such as the circuit node and the current sensors. In that regard the system is similar to present technology used in circuit breaker design. However there are some differences here also. The Node can be designed to provide the necessary communication and signal translation the system needs. In addition, the node can provide the self-powered protective functions that a normal circuit breaker trip provides. Hence, the basic over-current protective function can be performed in three places within the system: Each of the two C/CPU's and the node. So, where a normal circuit breaker would only have one trip on which it can rely, the redundant C/CPU single processor system has three. Double redundancy.

B. HEALTH SELF-MONITORING

The ability to interconnect all important components via serial communications and to include in each digital component large amounts of processing capability enable the components to monitor each other's health.

Each of the C/CPU's has the ability to detect and communicate any miss-operation in the other and in the nodes. Powerful diagnostic capabilities can be designed that can identify any one missing signal such that even loss of the current output of a single CT could be immediately identified.

This allows the user to identify an incorrectly operating component immediately and, in most cases, repair it without any loss of protection or control functions. This is a reliability enhancing capability not available in today systems where all the electronic metering and protection devices are not redundant, independent and communicate only high level information to central computer.

C. WIRING AND COMPONENT REDUCTION

The ability to use serial communication between all devices makes the normal point to point wiring common in power distribution control obsolete. A modern Low-voltage power circuit breaker may have 72 secondary disconnects. In addition, even PLC-based control can have a significant number of I/O connected to it. Additional metering and external protective relaying would add more intelligent electronic devices (IED), more sensors and more wiring. Each of these with multiple connection points, multiple wires and each of these wires may have multiple connection points as they wind their way through the distribution equipment. Serial communication of all information that pertains to the circuit breaker and each individual circuit significantly reduces the amount of wiring and connection points required. Reliance on one set of sensors for all information and one CPU for all data processing produces significant hardware reductions and wiring reductions in excess of 85%. This simplification in wiring can correlate to an increase in reliability due to the reduction in potential failure points and simplification of the entire system.

The single processor system is able to treat each circuit breaker as a pure switching device, so that sensing and all information that pertains to the circuit can now be associated to the

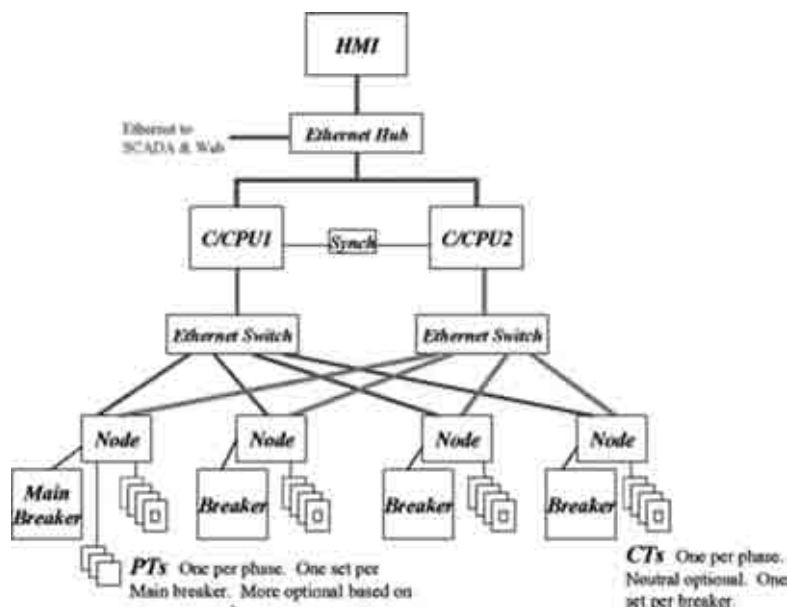


Fig. 11 System architecture diagram for a Single Processor System

nication switches and communication networks. In addition the control power sources required for any of the components is able to be designed with multiple levels of redundancy and variation in source type, such as either end of a substation, UPS, station batteries, etc.

Components that are not redundant fall into two categories:

Those not essential to the protection functions and those affecting or associated with a single circuit breaker.

In the first category is the Ethernet Hub that provides the communication link to the HMI. The HMI is not involved in the actual control process in the equipment. Furthermore, the system can accommodate additional hubs and HMI screens.

The synch function between the C/CPU's provides an additional synchronization function redundant to the synchronization function inherent in the dedicated communication network between the nodes and the C/CPU's.

This synchronization becomes important only in the case

circuit breaker position rather than the circuit breaker itself. The sensors and the circuit node may be located in the cubicle rather than the circuit breakers. This significantly reduces the variation and complexity in the circuit breakers.

The standardized circuit breaker provides for much shorter circuit breaker change-out times and more efficient spare part allocations. In summary, shorter Meant Time to Repair (MTR).

V. CONCLUSION

The authors believe that the single-processor concept, coupled with a communication and data-acquisition architecture that allows 6- μ s information resolution, simultaneous capture and processing of all system parameters, deterministic communication and control of all protective devices in the system, and faster than one-half cycle reaction to all fault scenarios will allow significant improvements in electrical power systems protection, reliability and diagnostics.

The benefits can be briefly summarized as follows:

1. Dynamic backup protection of each feeder device by the main device at any current setting without compromising selectivity or protection of either the branch circuit or the main bus.
2. Dynamic zone selectivity that is able to discriminate any current level in the feeder's protection range and adjust time delays at the main breaker to match the needs of that particular circuit regardless of how it is set.
3. Bus-differential protection able to discriminate bus fault currents in the current range of arcing faults with no need for artificial delays to achieve selectivity.
4. Ground-fault protection able to operate at any time delay above one-half cycle without protection compromises to achieve selectivity.
5. System-wide data capture for event diagnostics synchronized as accurately as a single data sample.
6. Redundancy in protective function and associated hardware.
7. Self-diagnostic capability enabling fast repair without loss of functions during diagnosis of the problem.
8. Simplification of construction, components and wiring driving enhanced reliability. Best of all, the single processor is able to cost-effectively achieve all of these functions simultane-

ously, without encumbering the equipment with multiple protective, metering, and sensing devices, each specialized for a single function.

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VII. VITA

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ARC RESISTANT SWITCHGEAR RETROFITS

Courtesy of Magna Electric

INTRODUCTION

In today's ever changing environment of electrical power distribution equipment and systems, safety and reliability are becoming the focal point of utility and industrial switchgear users. Many of these locations have upgraded their systems by converting older air circuit breakers to vacuum or by ordering new systems that are "Arc Resistant". However, many are not aware of the opportunity to upgrade existing switchgear cubicles to arc resistant retrofits achieving optimum safety for operating personnel and reliability of installed systems. Arc Proof retrofits of existing metal clad and metal enclosed switchgear is available for lineups of most manufacturers and vintages.

Members of governing bodies (such as the NFPA 70E)

New switchgear installations require a more stringent standard than older vintages. Associations such as EEMAC (Electrical Equipment Manufacturers Association of Canada), IEEE (Industrial Electrical & Electronics Engineering Society), IEC (International Electrotechnical Commission) are specifying the requirements for new safety features in switchgear. Through the door racking of circuit breakers, separate instrument sections and various other features are now standard on new equipment to provide additional safety for operators. New switchgear can also be ordered as arc resistant, providing the highest level of safety to operating personnel by reflecting internal arc byproducts in a safe direction.

The following article discusses the options available for

ARC-RESISTANT SWITCHGEAR

RETROFITS

As current switchgear models are available for most manufacturers and vintages of metal clad and metal enclosed switchgear, the 300-circuit, 15kV construction, front door, combined with an arc-resistant ventilation system is installed on your existing mainline, terminals can generally be done in less time than installing entire 15kV metal enclosed switchgear.

NEW

Most utility and industrial users of medium voltage switchgear order their new equipment designed to meet arc-resistant standards. Our designs are tested to meet and exceed the standards described in IEEE C37.20.7.

are becoming more concerned about an increasing number of accidents and injuries from electric arcing faults. Extreme temperatures and pressures as well as electromagnetic radiation are all effects that need to be dealt with to provide optimum safety for plant operations personnel. Incident energy and arc flash boundary are becoming increasingly important in the everyday operation of power distribution systems.

upgrading previously installed medium-voltage switchgear to an arc resistant design. The designs discussed in this article have been tested to EEMAC G14 -1 and meet IEEE standard C37-20-7. This process can apply to commonly found utility and industrial installations throughout North America.

ELECTRICAL FAULTS & ARCS

There are a variety of circumstances that result in internal arcs in electrical switchgear. Often times this failure occurs when the breaker fails during routine switching or when clearing a through fault. A dangerous situation also exists when a breaker fails to properly open prior to removal or insertion. Other causes of internal failure are due to partial discharge activity that weakens the insulation over time. Normally, any line surges on equipment with weakened insulation are subject to internal failure. Operational mishaps can occur to cause internal faults such as tools, jumpers or other equipment left in a cubicle during routine maintenance checks.

INTERNAL FAULTS IN SWITCHGEAR



The extent of protection against occurrence of internal faults varies depending upon the type of switchgear installed. The lowest level is plain Metal-Enclosed switchgear. Mid-level protection is found in the various forms of "Hybrid" Metal-Enclosed and the highest-level protection is Metal-Clad. Should, however, an internal fault

occur, none of the above is designed to withstand its effects. There is much confusion with the through fault interrupting capability of the switchgear as also applying to an internal fault withstand capability. This is not the case.

INTERNAL CONSEQUENCES

When an internal arc occurs in a switchgear cubicle, there are a variety of phenomena that occur. Depending on the amount of available fault current and its duration, a certain quantity of hot gases, hot glowing particles and super heated air are produced. There are also potentially toxic components (from insulation and other materials) and vaporized metal particles (plasma). Another major occurrence in this situation is a sudden large internal pressure rise.



EXTERNAL CONSEQUENCES

There are a number of external consequences that occur during a switchgear arc and failure. Pressure will force particles and gases out of holes, cooling vents and any gaps. With no designed controlled escape point, the weakest part of a gear will fail. Pressure at the front door can be between 50,000 and 100,000 pounds static. Front or rear doors are most likely points of failure leading to personnel injury. All of the above occurs in less than 10 cycles.

This normally is not enough time for a protection relay and upstream breaker to react.

There are up to 4 stages of events during an internal fault.

Stage 1 is the compression stage and starts at "Arc Event" time zero and continues to a point of maximum internal pressure. (less than 10 cycles)

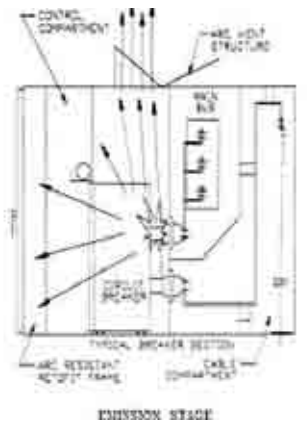
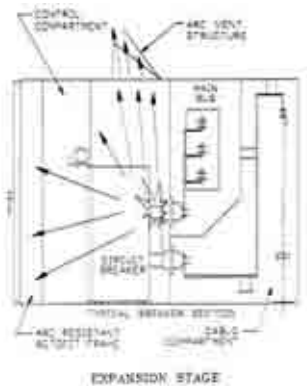
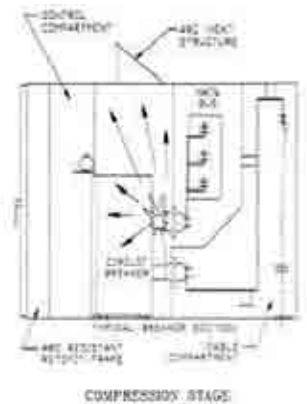
Stage 2 is the expansion stage and starts when the pressure relief vent begins to open, ending gas flow. This stage is characterized by wave motion and possible under-pressure with a duration of 5 to 10 milliseconds.

Stage 3, the emission stage, starts when the pressure relief vent has opened and ends when the gas in the cubicle reaches arc temperature. Duration of stage 3 is typically 50 to 100 milliseconds.

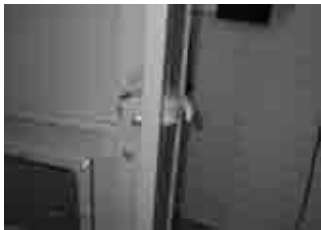
The thermal stage in this process is stage 4 and lasts until the arc is extinguished and all combustible material has been consumed. The greatest damage to the equipment occurs during this last stage.

ARC RESISTANT SWITCHGEAR TYPES

Based on the EEMAC standards, there are 3 types of arc resistant switchgear. Type A requires protection from the effects of an internal arc in the front of cubicle to a height of 2 meters. Type B provides protection in the front, rear & exposed side of cubicle to a height of 2 meters. Non exposed sides are excluded in type B. The last type is type C which is the same as type B with the additional provision of inter-compartmental protection with the exception of the main bus compartment. EEMAC also requires that the building housing the switchgear be considered in the overall design by the end user. IEEE is similar but contains some variations.



RETROFITTING EXISTING SWITCHGEAR TO ARC PROOF



Switchgear retrofits to arc resistant design are available for most manufacturers and also for most vintages of switchgear. Tested designs meet all EEMAC and IEEE standards for protection.

Switchgear cubicles with newly installed vacuum breakers are prime candidates for cubicle upgrades to arc resistant. Vacuum retrofits have already extended the life of the switchgear by adding a new breaker. The circuit breaker is the device that normally shortens the overall life due to characteristically having numerous moving parts. The switchgear cubicles themselves will last for a very long time due to the fact that they have limited moving components.

Modern switchgear arc resistant retrofits allow for system switchgear to be upgraded to include the cubicle front door and steel framework and associated protection or metering if so desired. The doors are a heavy duty design with multiple hinges and locking devices to guarantee that arc blast does not escape through the front door of the switchgear. The extra strength locking devices on the handles work in conjunction with the cubicle modification to ensure the door cannot open under the extreme force. In order to mount such a door a heavy duty steel frame is also installed.

One of the major exposures that operating personnel experience when operating metal clad switchgear is during the racking in and racking out of circuit breakers. Anyone that has performed this operation recognizes a distinct sound that occurs when the breaker is just making or breaking the primary connection of the power stabs from the finger clusters to the main bus stabs. That distinct sound is air ionizing and this ionized air can



compromise the insulation value of the phase to phase dielectric inside the cubicle.

Through the door racking is a requirement of all switchgear arc resistance retrofits. This upgrade means that the operator will rack the circuit breaker in and out with the door closed. The possibility of exposure during failure is extremely limited during this process.

One of the major factors in releasing energy contained inside switchgear cubicles is to providing an intricate venting system. It is common when a switchgear cubicle fails that the damage cascades to other cubicles or to other equipment located in the same room. A cubicle failure can destroy overhead cable tray or adjacent control system mimic panels or control sections resulting in weeks or months of downtime for equipment and systems outside the immediate cubicle area.

The venting system employed in arc resistant retrofits is a key to releasing the energy in a controlled manner. Optimum safety of the personnel, as well as decreased damage to equipment in the surrounding area, is the key to each individual design. All this means a higher degree of safety for site personnel and limiting the degree of downtime suffered.

Outdoor houses are particularly susceptible to major damage when a breaker cubicle or cable entry section fails. It is common that smoke, heat and flash damage can virtually immobilize entire outdoor switchgear and control houses. Venting to outdoor is a key to limiting the damage.



TESTING DETAILS

Retrofit designs are tested at a certified laboratory on typical switchgear cubicles to meet the standards as discussed in this article. An internal short circuit is established to test the retrofit's capability to withstand the sudden temperature and pressure rise. Indicators are located at numerous points within 10 centimeters of the switchgear. The internal fault is set up to establish the maximum stress on the design and establish the capability of the arc resistant retrofit. Typically, test currents exceeded 30,000 Amps RMS with a peak of 75,000 Amps for a full 60 cycles.



SUMMARY

Operations personnel are exposed to potential hazards during normal operation of power distribution switchgear due to the extremely high levels of energy that are involved when switchgear fails. Arc resistant retrofits are a great option for life extension, improved productivity and most importantly operating personnel safety. These retrofits are available for most manufacturers and vintages of switchgear and should be considered for any application where the safety of personnel or the reliability of equipment is a major concern.

CHECKING ELECTRICAL ROOMS

Courtesy of Royal & SunAlliance, Engineering Insurance & Loss Control Services

CHECKING ELECTRICAL ROOMS

1. Any unusual odors in electrical rooms should be checked out immediately. It usually means there is overheating somewhere in the panels. Electrical insulation that is overheated will give off an odor that is very noticeable.

2. In order to keep main disconnect switches and circuit breakers in good operational condition, it is recommended they be exercised annually.

3. Transformers should be checked to insure air intake grills are clean and that there are no objects stored around the transformers that can block the cooling air supply. Transformers generate heat and this heat must be removed or the insulation will break down causing eventual failure of the transformer.

4. All electrical rooms should be locked and entry restricted to school custodial and maintenance staff, or other authorized persons.

5. Electrical rooms should not be used for storage purposes. Stored material will restrict access to the electrical panels in the event of emergency and may restrict air supply to transformers. If materials are not stored in electrical rooms, it also will discourage entry by unauthorized persons.

6. When checking electrical rooms, a hand can be put on the various circuit breaker and switch panels. If any are hot to the touch it is an indication that overheating may be occurring and this should be checked immediately.

7. Any unusual sounds from



transformers or electrical switchgear should be investigated.

8. Electrical rooms containing transformers are usually ventilated to remove the heat generated by these transformers. Inadequate ventilation will cause high ambient temperatures to occur in the electrical rooms and may cause the transformers to overheat.

Other considerations for checking electrical panels and transformers as part of the PM (preventative maintenance) program would be:

1. Thermographic scanning of the electrical switchgear and transformers, especially in larger regional schools that are supplied with 600 volt 3 phase power.

2. Electrical panels and switchgear in smaller schools could be checked annually by an electrician. This would include opening up the panels, visually checking for hot spots, and tightening of cable connections.

An example of the problems that can occur if electrical panels are not maintained and checked is shown in these photos. These photos are of fused disconnect on a 600 amp/600 volt main electrical service for a retail store. One 60 amp fused disconnect overheated and the insulation eventually started on fire. The fire spread up to the panels above before it was eventually put out by the Fire Department. The cause is thought to have been a loose connection at the fuse holder in the disconnect switch. The repair costs amounted to about \$100,000 and the store was closed for two days.

CIRCUIT PROTECTION METHODS: DIFFERENTIATING BETWEEN SUPPLEMENTARY PROTECTION, BRANCH CIRCUIT PROTECTION AND SELF-PROTECTED DEVICES

Courtesy of Allen-Bradley, Rockwell Automation

INTRODUCTION

Modern electrical equipment continues to increase in complexity and importance in industrial, commercial, and residential installations. This equipment is often considered critical for normal system operations. As such, the importance of circuit protection and overall equipment protection continues to increase and is a very important topic to understand.

Determining whether a circuit is adequately protected can require a high-level view of the electrical distribution system, from the fault current available at the source of supply down to the end device connected in the system. Circuit protection includes protection from equipment overload conditions, undervoltage and overvoltage conditions, ground faults, and short-circuits.

Although mandated by code for any electrical installation, the proper implementation of circuit protection products can be confusing at times. Occasionally, this confusion results in circuit protection products that are installed in circuits where their use is not appropriate.

From a machinery design standpoint, system engineers and equipment designers must choose appropriate protective devices to ensure the safety and reliability of their products. Circuit protection devices protect expensive systems by rapidly disconnecting power to components in the event of an abnormal operating condition. Even though guidance exists in the form of the various electrical codes, the wide variety of product offerings can make the proper selection of circuit protection devices a challenge. An understanding of circuit types and circuit protection products is critical to ensuring their proper application. Products addressed in this white paper will include circuit breakers made in accordance with UL 4891, supplementary protectors made in accordance with UL 10772, and manual motor controllers as defined in UL 5083. Application and product use will be explained as suitable for North American installations.

HISTORY

In the US, the National Electric Code (NEC) exists to guide electricians in the proper installation of electrical equipment and defines the specific requirements for circuit protection.(5) The focus of the NEC, which is a code developed by the National Fire Protection Association (NFPA 70), is primarily fire prevention. Circuit protection is required to prevent fires from occurring due to overcurrent faults or short-circuits. In Canada the Canadian Electric Code (CEC) exists to provide

similar guidance. Other areas of the world have equivalent country or local codes. In Europe, IEC is the most familiar guiding organization, but there is also VDE of Germany, KEMA of the Netherlands, and SEMKO of Sweden. Each of the regulatory bodies or testing agencies may be recognized as the guiding body for a specific geographical area. They define performance criteria and proper use of electrical equipment and components in a given location. More importantly, they provide independent verification of manufacturers' self-certification of products to the various IEC standards.

Much of the confusion associated with proper application of circuit protection products is related to product use in North American markets. History has shown that there is a certain amount of confusion and misunderstanding regarding the meanings and proper application of circuit breakers, supplementary protectors, circuit breakers for equipment, and branch circuit protection devices. Some of this confusion is related to the look and function of these devices and the differences in how they can be applied in other areas of the world. It is not uncommon for overseas-manufactured equipment coming into the US or Canada to be red-tagged by UL or CSA inspectors because it does not meet the North American circuit protection requirements.

The different codes for the US, Canada, and the rest of the world have corresponding and unique definitions for circuit breakers. A "circuit breaker's" primary function is to protect wire. In North America, the term "circuit breaker" generally refers to a device which is a UL 489/CSA 22.2#5.1 constructed device. In other parts of the world, there are other guidelines for circuit breaker definition. Differences between UL, CSA, and IEC codes reflect the differences in technical definition from country to country. As a result, items categorized as IEC circuit breakers (miniature circuit breakers or circuit breakers for equipment) do not always comply with the UL or CSA standards. Miniature circuit breakers are common in the world's IEC marketplaces, but in North America these devices are normally referred to as supplementary protectors.

Again, this document will focus on North American applications, which are governed by the NEC and CEC.

DEFINITIONS

The following definitions were taken from the UL standards: UL 4891, UL 10772, and UL 5083 and are provided here as a reference:

Available Fault Current (AFC): The current in a circuit which would flow if a short-circuit of negligible impedance were to occur at a given point.

Branch Circuit: The conductors and components following the last overcurrent protective device protecting a load.

Branch Circuit Protection: Overcurrent protection with an ampere rating selected to protect the branch circuit. For a motor branch circuit, the overcurrent protection is required for overcurrents due to short-circuits and faults to ground only.

Branch Circuit Protective Device: A fuse or circuit breaker that has been evaluated to a safety standard for providing overcurrent protection.

Circuit Breaker: A device designed to open and close a circuit by non-automatic means, and to open the circuit automatically on a pre-determined overcurrent, without damage to itself when properly applied within its rating.

Class 1 Circuit: A control circuit on the load side of overcurrent protective device where the voltage does not exceed 600V, and where the power available is not limited, or control circuit on the load side of power limiting supply, such as a transformer.

Class 2 Circuit: A control circuit supplied from a source having limited voltage (30V rms or less) and current capacity, such as from the secondary of a Class 2 transformer and rated for use with Class 2 remote-control or signaling circuits.

Control Circuit: A circuit that carries the electric signals directing the performance of a controller, and which does not carry the main power circuit. A control circuit is, in most cases, limited to 15 A.

Control Transformer: A transformer whose secondary supplies power to control circuit devices only (excluding loads).

Interrupting Rating: The highest current, at rated voltage, that a device is intended to interrupt under standard test conditions.

Let-through Current: The maximum instantaneous or peak current which passes through a protective device.

Manual Motor Controller (with disconnect rating): An electrical device suitable for the switching on and off of motor loads. Manual motor controllers must meet the requirements of UL 508, pass the additional dielectric voltage withstand test (specified in UL 508) following the appropriate short-circuit test in that standard, and pass the extended mechanical operations test as specified in the endurance test of UL 508. Manual motor controllers that carry a motor disconnect rating must be marked "suitable as motor disconnect". For a motor disconnect rating the operating means of a manual motor controller shall be provided with a method of being locked in the off position.

Note: Per the definitions of the NEC (and CEC) and UL/CSA, a branch-circuit inverse-time circuit breaker is permitted as a controller for all motors. (NEC 430.83.A.2)

Supplementary Protection: A device, typically either a supplementary fuse or a supplementary protector (see below), intended to provide additional protection subsequent to branch circuit protection. This device has not been evaluated for providing branch circuit protection. The purpose of a supplementary protector is to provide additional protection for a given piece of electrical equipment - it does not serve as branch circuit protection.

Supplementary Protector: A manually resettable device designed to open the circuit automatically on a pre-determined value of time versus current or voltage, within an appliance or other electrical equipment. It may also be provided with manu-

al means for opening or closing the circuit. A supplementary protector's primary function is to protect equipment.

Self-Protected: A qualifying term applied to a controller that contains coordinated overload and short-circuit protection. A self-protected controller is evaluated as a complete unit whether comprised of a single or multiple components. Coordinated protection is able to be inherent or obtained by correct selection of components or accessory parts in accordance with the manufacturer's instructions.

Withstand Rating: The maximum current that an unprotected electrical component can sustain for a specific period of time without the occurrence of extensive damage.

STANDARDS

In the United States, there are three basic categories for circuit protective devices as they relate to this document: UL 489, UL 1077, and UL 508. An additional category, which is a subset within UL 508 that defines self protected (Type E) devices, will be added for discussion. The Canadian equivalent standards are CSA 22.2#5.1, CSA 22.2#235, and CSA 22.2#14. This document will attempt to explain the differences between products tested and rated to these standards, and will describe their applicability in field installations.

UL 489 - CIRCUIT BREAKERS

A definition for what a circuit breaker is depends primarily on your location in the world. A general circuit breaker definition from UL is, "a device designed to open and close a circuit by manual means, and to open a circuit automatically on a pre-determined overcurrent, without damage to itself when properly applied within its rating." (1) But this UL definition leaves much open to interpretation. For clarification, in the US, a circuit breaker is a device constructed to and performing in accordance with UL standard 489. UL 489 devices are recognized as providing branch circuit protection. In Canada, CSA 22.2#5.1 provides equivalent design and performance guidance.

UL 489 is the standard that defines products often identified as molded-case circuit breakers (MCCBs). (1) It also addresses molded-case switches (MCSs) as well as circuit breaker enclosures (CBEs). Molded-case circuit breakers are specifically intended to provide service entrance, feeder, and branch circuit protection in accordance with the NEC.

Molded case circuit breakers that are built to the UL 489 standard, also meet the requirements of CSA 22.2#5.1. They can be used as service feeder or branch circuit protective devices. As circuit breakers, they can provide motor branch circuit protection and can be used as a disconnecting means.

Historically, product size is one of the differentiating factors between UL 489, UL 1077

and UL 508. Generally, UL 489 devices were relatively large in physical size due to the spacing requirements dictated by the standard, and historically did not have current ratings below 15 A for installations up to 600V AC. The large spacing between

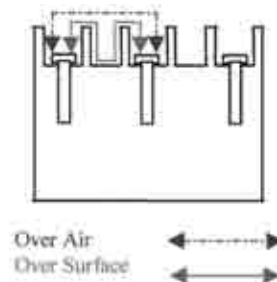


Figure 1

conductors, 1 inch through air and 2 inches over surface, meet UL and NEC requirements for service entrance applications. See Figure 1 for over air and over surface examples of spacing between conductors.

UL 489 allows for smaller spacings at voltages below 300V. Some of these UL 489 products are now being produced with voltage limits in the 240V AC range. UL 489 circuit breakers, which are used up to the 600V AC level, are commonly found with Available Fault Current (AFC) ratings in the 50 kA...100 kA range or higher. This means that they are capable of breaking a circuit whose source of supply could deliver fault currents up to those levels.

Today UL 489 devices are readily available in specific voltage ranges and with current ranges below 15 A, allowing closer sizing between load and protection.

Most UL 489 circuit breakers up to 600V are not current limiting, meaning that when they trip, they rely upon the zero-crossing characteristics of the current waveform for complete circuit interruption. Under these conditions, the let-through energy can be quite high and components affected by the fault, which might include a critical load, will be subject to a high level of electrical energy.

As a branch circuit protection device, UL 489 circuit breakers are tasked with protection of the circuit wiring. Their purpose is to help prevent electric shock and fire, and to provide a means for electrical isolation during maintenance periods. A key point to note here is that they do not necessarily serve as protection for the connected electrical load.

UL 1077 - SUPPLEMENTARY PROTECTORS

Supplementary protectors are another circuit breaker type of device which are built to comply with UL 1077. As the name implies, supplementary protectors serve to supplement the circuit protection that is already in place. Where UL 489 devices are tasked with conductor protection, protection of the load is the primary purpose of selecting a UL 1077 device. They are circuit breaker type devices because their function meets the definition of a circuit breaker, even though they are not categorized as circuit breakers in US and Canadian markets. One key difference between circuit breakers and supplementary protectors is the physical size of the device. UL 1077 spacings for applications up to 600V AC are 3/8 inch through air and 1/2 inch over surface. These smaller spacings allow for a smaller product to be produced, but also impose some restrictions on how the product can be used. Whereas UL 489 devices may have AFC ratings in the 50 kA...100 kA range or higher, supplementary protectors generally have AFC ratings of 10 kA or less. Supplementary protectors are not branch circuit protective devices because they are not recognized by UL or CSA as providing conductor short-circuit protection. As stated earlier, protection of the load is one of the primary purposes for selecting a supplementary protector.

The Canadian standard for supplementary protectors is CSA 22.2#235. CSA states that supplementary protectors are, "intended to be components within an appliance or other electrical equipment." (6) These devices are purposely intended to be tailored to the overcurrent protection requirements of a specific load and application. Supplementary protectors can provide various types of protection. They can be used as overcurrent, over-voltage, or undervoltage protection within an appliance or other electrical equipment.

The supplementary devices addressed in this document

are overcurrent protection devices.

These devices can be used as long as branch circuit overcurrent protection is already provided or is not required. The supplementary protector must be suitable for continuous use under the conditions that are seen in actual service. These conditions include the inrush current of the device being protected, circuit voltage, continuous current in the circuit, and other operating conditions. Therefore, individual applications may need special review to determine if the supplementary protector will be affected by the design of the equipment in which it is used. Acceptable use of the supplementary protector is determined by the conditions found in its actual installation.

Suitability of the supplementary protector is dependent on other components in the installation. A sample of these components and related items to consider include: the ratings and types of upstream protection, transformer sizes and their deliverable currents in a fault condition, conductor impedances and lengths, and characteristics of the connected load. A review at the system level, not at the individual component level, will be required for proper product selection.

Neither CSA nor UL identifies a specific requirement for an interrupt capacity for supplementary protectors. However, most manufacturers do identify a component interrupt capability, identified by the published short-circuit current rating in UL's recognized component directory (yellow card data). It is important to note that the manufacturer selects the criteria by which the product will be tested, and that there are several variations of the short-circuit current rating qualification. For example, the Allen-Bradley 1492-CB has a 3 kA interrupt capability at 480V AC, with a SC code of U2 (tested without additional series overcurrent protection and passing re-calibration after the short circuit test). It is important to note that neither US nor Canadian installations allow the interrupt capability of the supplementary protector to be used to meet the code requirements for branch circuit protection in a given installation. The load must have short-circuit protection available from some other circuit component located upstream of the supplementary protector to provide the branch circuit protection. Supplementary protectors must not be installed in installations where their interrupt ratings are exceeded.

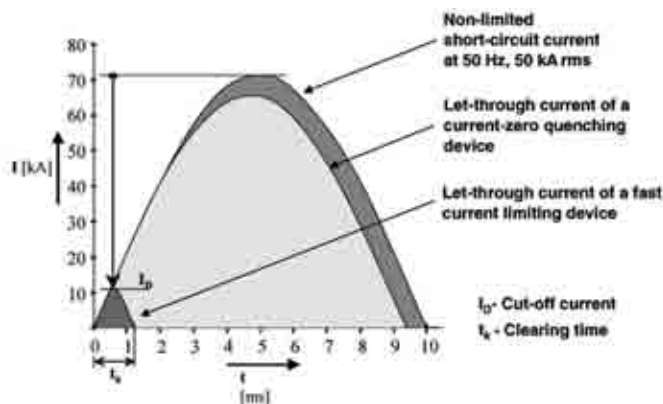


Figure 2

Some supplementary protectors provide the added benefit of current limitation. A current-limiting device is capable of providing enhanced protection beyond that of a conventional circuit breaker. A current-limiting device does not rely upon the zero crossing of the current waveform and can be faster acting

than a conventional breaker, therefore limiting the electrical energy seen during a fault condition.

A graphical representation of the difference in let-through current between a current limiting breaker and non-current limiting breaker is shown in Figure 2.

DIFFERENCES BETWEEN CIRCUIT BREAKERS AND SUPPLEMENTARY PROTECTORS

As shown in Figure 2, the current-limiting function of a fast acting supplementary protector significantly reduces the let-through current seen in the event of a short-circuit fault. This benefits the electrical system by reducing the electrical energy that attached equipment and components can be exposed to if a fault occurs. Generally, let-through energy of a current limiting supplementary protector is reduced to a level of 1/10th or less of that experienced when using a device relying on the zero-crossing current characteristics.

Using a residential example may show the differences between a circuit breaker and a supplementary protector. In most homes there is a circuit breaker box (or fuse box) that is used to protect the wiring within the house. Typically most of the circuit breakers are 15 or 20 A and the wire is sized to be protected by those circuit breakers.

In many homes, the kitchen sink contains a garbage disposal. If you put too much into the disposal, the disposal stops working. When you allow the disposal to cool and then press a reset button on the disposal, the disposal will work again.

This button is a reset of a supplementary protector incorporated into the disposal. The supplementary protector provides additional protection for the disposal, on top of the branch circuit protection provided in the centralized location. Typically, that protector is about one (1) or two (2) amps to provide protection for the motor in the disposal. If the 15 A allowed by the wiring protection from the centralized circuit breaker were to flow to the disposal, the disposal motor would be destroyed.

The supplementary protector provides:

- Equipment protection of the motor
- Local protection near (on) the disposal
- Isolation of the individual load
- Is “in addition” to the wire protection of the house wiring

In the same manner in North American industrial equipment, branch circuit protection is used to provide wire protection and supplementary protectors are used to provide equipment protection.

ALL SUPPLEMENTARY PROTECTORS ARE NOT EQUAL:

The UL 1077 standard allows for several levels of testing for products identified as supplementary protectors. Each manufacturer may specify the capability of the supplementary protector products within some guidelines. A sample of tabulated data taken from UL's recognized component directory for one company's supplementary protectors is shown on this page.

CSA is currently developing similar performance codes to identify product performance capabilities. There are several categories that are identified to establish appropriate use for supplementary protectors, which include: Use Group (UG), Terminals (FW), Maximum Voltage (Max V), Maximum Amperage (Max Amps), Tripping Current (TC), Overload Rating (OL), and Short-Circuit Current Rating (SC).

Type	OC - Overcurrent UV - Undervoltage SPV - Shunt protector, voltage	OV - Overvoltage SPOC - Shunt protector, overcurrent
Use Group	A - General Industrial B - Household Kitchen Appliances	C - Household Appliances D - Commercial Appliances
Terminals	0 - Suitable for Factory Wiring Only 1 - Line Terminals Evaluated for Field Wiring 2 - Load Terminals Evaluated for Field Wiring 3 - Line and Load Terminals Evaluated for Field Wiring	
Max V	Identifies the maximum (50/60 Hz) voltage at which the protector has been tested.	
Max Amps	Identifies the amperage rating for the protector or family of protectors.	
Tripping Current	0 - Tripping Current is less than 125% of the amp rating 1 - Tripping Current is 125% - 135% of the amp rating 2 - Tripping Current is more than 135% of the amp rating and is designated by the manufacturer	
Overload Rating	0 - tested at 1.5 times the amp rating for general use 1 - tested at 6 times the AC amp rating or 10 times the DC amp rating for motor starting	
SC Rating	C - Indicates that the short-circuit test was conducted with series overcurrent protection U - Indicates that the short-circuit test was conducted without series overcurrent protection 1 - Indicates that a re-calibration was not conducted as part of the short-circuit testing 2 - Indicates that a re-calibration was performed as part of the short-circuit testing	

Each of these categories has several possible ratings:

All of the observed categories are important, but probably the most significant difference is in the area of the short-circuit test rating. When comparing supplementary protectors, the shortcircuit withstand rating, suitability for further use (re-calibration verification) and test success without a series fuse are significant performance differentiators. Devices that are recognized as passing the short-circuit test without a series fuse have greater application flexibility than products that require a series fuse to pass the same tests. The installation examples in this document assume a SC rating of U2, which has been achieved by the 1492-CB series of Allen-Bradley products.

Application of supplementary protectors in UL 508A industrial control equipment generally is included in the equipment's "procedure", describing the method of use and selection.

UL 508 - INDUSTRIAL CONTROL EQUIPMENT

UL 508 is the standard which defines the requirements for industrial control devices and their accessories.(3) Devices recognized as UL 508 components are intended to be used for starting, stopping, regulating, controlling, or protecting electric motors and industrial equipment.

Equipment covered by UL 508 is for use in ordinary locations in accordance with NFPA 70 of the National Electrical Code.(5) These requirements also cover industrial control panels that are assemblies of industrial control devices and other devices associated with the control of motor operated and related industrial equipment. Examples of devices in an industrial control panel are industrial control devices, disconnecting means, motor branch circuit protective devices, temperature control devices, and electrical instruments. The spacing requirements for UL 508 are the same as UL 1077, which are 3/8 inch through air and 1/2 inch over surface for applications up to 600V AC. There are numerous examples of industrial control

devices, such as motor starters, push button stations, control circuit switches and relays, proximity switches, programmable controllers, PLC outputs, etc.

UL 508 TYPE E SELF-PROTECTED DEVICES

As defined in UL 508, a Type E self-protected combination motor controller can serve the function of a disconnect, branch circuit protection, motor disconnect, and motor overload device.(3) This combined rating eliminates any additional requirements for upstream fuses or circuit breakers in installations utilizing a Type E device. Type E devices are generally used in an installation where several motor controllers are found in a common panel. Because of their component size and multiple functions, Type E devices are increasing in popularity.

When compared to traditional group motor installations, Type E devices simplify the installation because the requirement for the group fusing is eliminated. There are some additional requirements of a self-protected motor controller for its proper use. A Type E device must have a method of being locked in the off position. All ungrounded supply conductors must be broken when the device opens the circuit and the device must not be capable of independently breaking a single pole under normal service conditions. Because it provides protection for both short-circuit and overload conditions, a Type E combination motor controller must visibly indicate and differentiate which function, overload or shortcircuit, has occurred.

The field wiring terminals on the line side of a Type E combination motor controller are required to have the same spacings required in UL 489, which are 1 inch through air and 2 inches over surface. These spacings make the device suitable for installations up to 600V AC. The self-protected rating provides protection for itself, the connected load, and the conductors between the Type E device and the load. Additionally, some self-protected devices are suitable for tap protection as allowed in NEC 430-53(D)(3). This greatly expands installation flexibility by increasing the NEC allowable tap conductor ampacity ratio.

CIRCUIT TYPES

Circuit type plays a considerable role in determining what type of circuit protection device can be utilized. There are basically 3 main circuit types: feeder, motor branch, and control.

Control circuits are further broken into 2 sub-categories; class 1 control circuits, up to 600V and class 2 energy limited control circuits, up to 30V. Application of circuit breakers, supplementary protectors, and self-protected devices is very much related to circuit type.

The following diagram will help identify each of these circuit types.

CODES: NEC / CEC

A key element of this document is identification of the proper use of supplementary protectors. Information on how they can be applied in accordance with the various North American codes will be discussed next. Supplementary protectors are addressed in the NEC, but only in regards to motor control circuit overcurrent protection.(5) Supplementary protectors are specifically allowed within the NEC, where the motor control circuit is tapped from the load side of the motor branch circuit protection device, as shown in Figure 4. Other acceptable uses of supplementary protectors will be addressed later in this document.

Article 240-10 of the NEC states the following regarding supplementary overcurrent protection, "Where supplementary overcurrent protection is used for lighting fixtures, appliances, and other equipment or for internal circuits and components of equipment, it shall not be used as a substitute for branch circuit overcurrent devices or in place of the branch circuit protection specified in Article 210".(5) This clearly indicates that supplementary protectors simply supplement branch circuit protection and that they are not a substitute for branch circuit protection.

TYPICAL INSTALLATIONS

It was previously stated that supplementary protectors are used to provide more precise protection to a given load. But it is also necessary to ensure that they are appropriate for use in the installation. Some types of loads are specifically prohibited from having a supplementary protector as the protective component. Supplementary protectors cannot be applied as a motor branch, or branch circuit protection devices in either the US or Canada. Motor branch circuits can be protected by UL 489 devices, UL 508 devices in combination with a short-circuit protective device, or UL 508 Type E self-protected devices.

Supplementary protectors are specifically targeted at protecting control circuits, including some of the following types of loads: solenoids, test equipment, controller I/O, relay or contactor coils, computers, transformers, power supplies, medical equipment, and other control equipment. To be applied properly,

supplementary protectors require that some form of upstream, branch circuit protection already be in place in the installation. In basic terms, if there is an upstream overcurrent protective device in place which is of proper rating and type to protect the conductors (and the supplementary protector) feeding the circuit, if the circuit is a type which is appropriate for use of a supplementary protector, and if the fault current rating of the supplementary protector is not exceeded,

then a supplementary protector can be used in the installation. The benefits of supplementary protection include precise protection of the load components, a small installed size, resetability after a fault, tripping selectivity, and fault current limitation. Selectivity is detailed in the examples below:

ALLEN-BRADLEY CO INC 1201 S 2ND ST, MILWAUKEE WI 53204 Supplementary protectors.						E65138		
Cat. No.	Type	UG	FW	Max V	Max Amps	TC	OL	SC
1492GHD	OC	A,C	O	250v ac 80v dc	16	2	0	1.0KA, U1
1492GS	OC	B,D	3	277/480v ac	0.1-16	2	0	5.0KA, C1
1492GS	OC	B,D	3	277/480v ac	18-32	2	0	2.0KA, C1
1492CB	OC	A	O	120v ac 277/480v ac	0.5-50 0.5-50	2	0	10.0KA, U2 3.0KA, U2
				240v ac	0.5-50	2	0	5.0KA, U2

Cat. No. 1492-GHAXXX "XXX" may be one to three suffix numbers and/or letters.
Cat. No. 1492 followed by -C, followed by B or D, followed by 1, 2, 3 or 4, followed by suffix letters DF, DG, DH, F, G or H, followed by numerals, may be followed by additional suffixes.
Cat. No. 1492 followed by ACB, followed by A, CC, H, HS or S, followed by additional suffixes.

Marking: Company name or trademarks  and catalog designation.

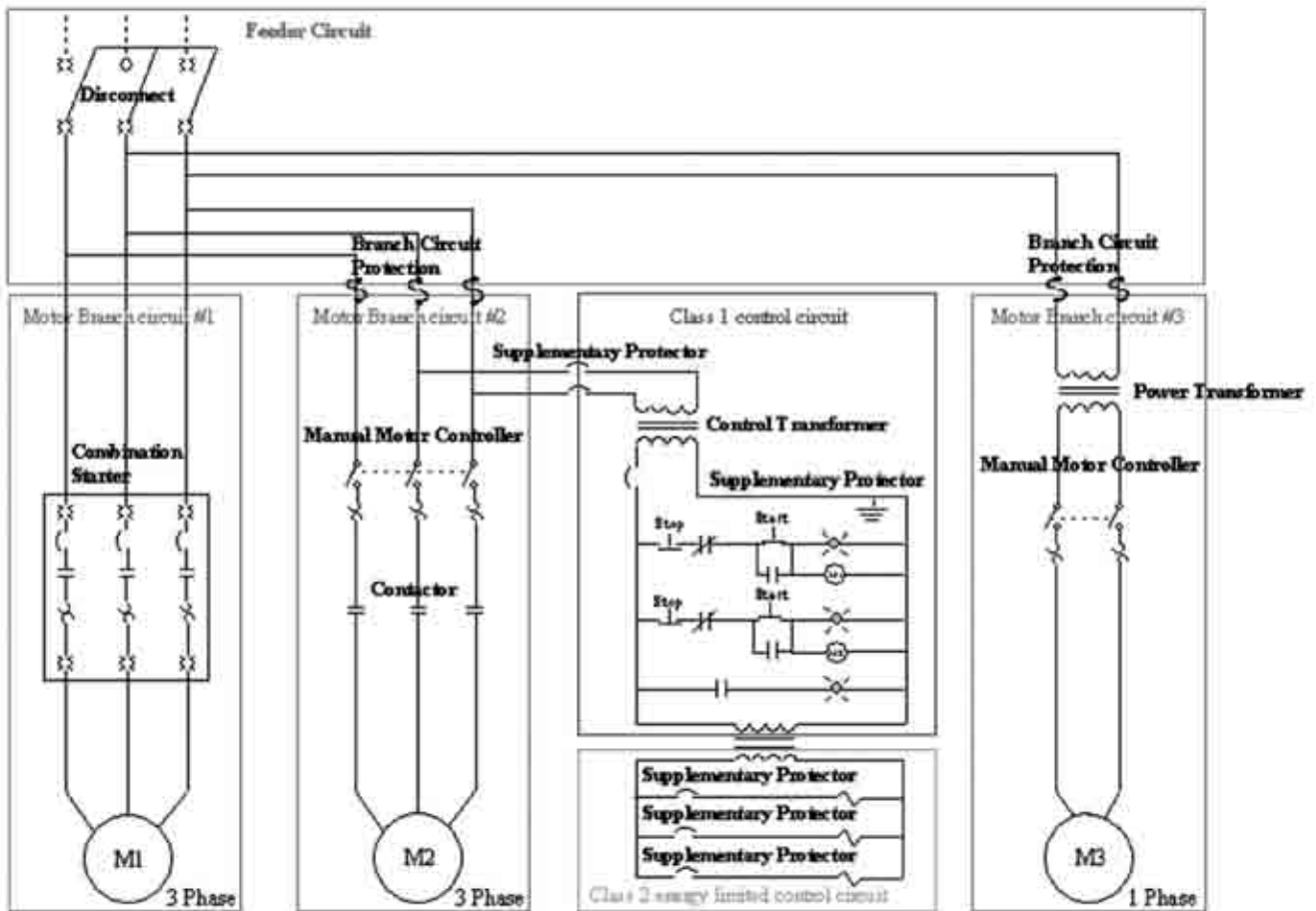


Figure 3

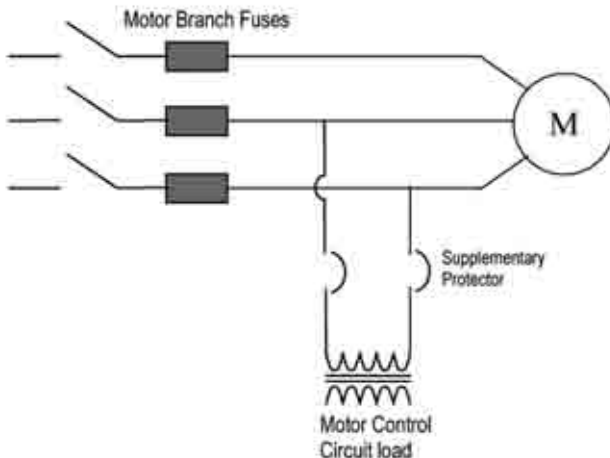


Figure 4

If a fault were to occur in the control circuit that is not using supplementary protectors, the entire circuit would be lost when the fuse blows and power would be removed from all loads.

Depending on the application, this could result in a loss of productivity. On the contrary, the same fault in the circuit with supplementary protection would only disable the part of the circuit where the fault occurred. The remaining loads would remain powered, and losses in productivity would be minimized.

SAMPLE CIRCUIT

The following circuit diagram shows several examples of how supplementary protectors can be properly applied. In this diagram, the main circuit breaker provides short-circuit protection for the 2 AWG wire that is feeding the various circuits. There are two control circuits, each with their own control transformer. Both control transformers are protected with fuses. In circuit 1, the control transformer has fuses on only the primary side which would be sized to protect the primary wiring, the transformer itself, and the secondary side wiring. In circuit 2 the control transformer has both primary side and secondary side fusing.

In both cases, the individual control loads are being protected by the supplementary protectors. Circuit 3 is a lighting/heating circuit that is protected by a 15 A fuse, with individual supplementary protectors for each load. Note that the wire gauge is 14 AWG, with an ampacity of 15, which is protected by the 15 A fuse. The individual loads fed by this conductor can then be protected with supplementary protectors.

TYPICAL LOAD TYPES

RESISTANCE HEATERS

UL 508A addresses the sizing of overcurrent protection for resistive heater loads.(4) Resistive heaters and other non-inductive loads are termed “fixed” loads, meaning that they are not subject to increased current levels due to overloads. They are, however, susceptible to fault current associated with a

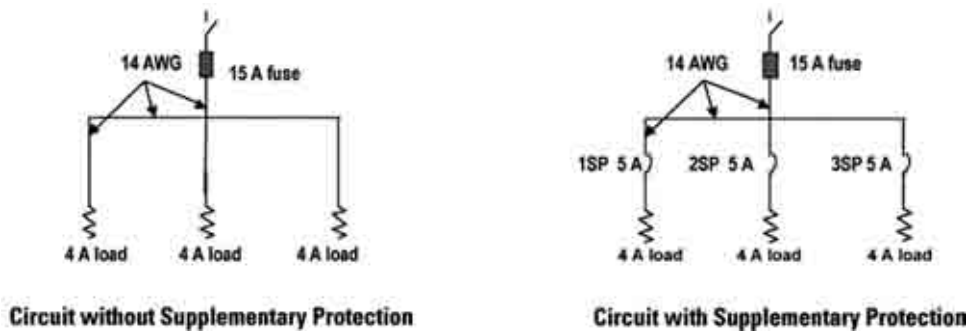


Figure 5

short-circuit. Fixed loads can be protected by supplementary protectors where appropriate upstream short-circuit protection is present. The wire in such installations must be sized for the load current. Addition of supplementary protection between the fuse or circuit breaker and the end load can provide selectivity, resetability, switching capability, and enhanced short-circuit protection. See Figure 7 for an example of such an installation.

RECEPTACLES - IN CONTROL CIRCUITS

Receptacles are generally considered branch circuits and

require branch circuit protection such as fuses or a UL 489 circuit breaker. But there is an exception when the receptacle is within a control circuit and has a specific intended use. If the control circuit is protected by a branch circuit protective device, UL 508A indicates that a lesser rated overcurrent protective device can be used for protection of the receptacle itself, as long as the ampere rating of the overcurrent device and intended use of the receptacle are marked.(4) Within a control circuit, the intended use is limited to devices associated with programming or equipment diagnostics. In these cases, a supplementary protector can be used as the overcurrent protective device. The key elements are that the receptacle is within a control circuit, has a specific intended use, and is properly identified as to its intended use.

However, many inspectors have insisted that the receptacle, even located within the control enclosure, is a general purpose device that can be used not only for the programming equipment but for general purpose devices such as a drill. They are insisting upon seeing the receptacle protected by a branch circuit breaker or branch circuit protection rated fuses.

Some inspectors and NFPA 79 insist that the receptacle be protected by a GFCI to protect an operator from the danger of a ground fault. UL 508A states that if the enclosure is designed for wet environments (such as type 3 or 4 or similar) the receptacle needs GFCI protection.

CONTROL TRANSFORMERS TRANSFORMER PRIMARIES

In US markets, Control circuit transformer primaries can be protected with supplementary protectors when there is upstream branch circuit protection available and when it is sized appropriately to protect the conductors feeding the control transformer. For example a 2 KVA transformer, 480V/120V, with 1% impedance has a rated primary current of $2000 / 480 = 4.2$ A.

Assume that the conductor on the primary side is 14 AWG with an ampacity of 20 A. Since the primary current is 4.2 A, UL 508A dictates

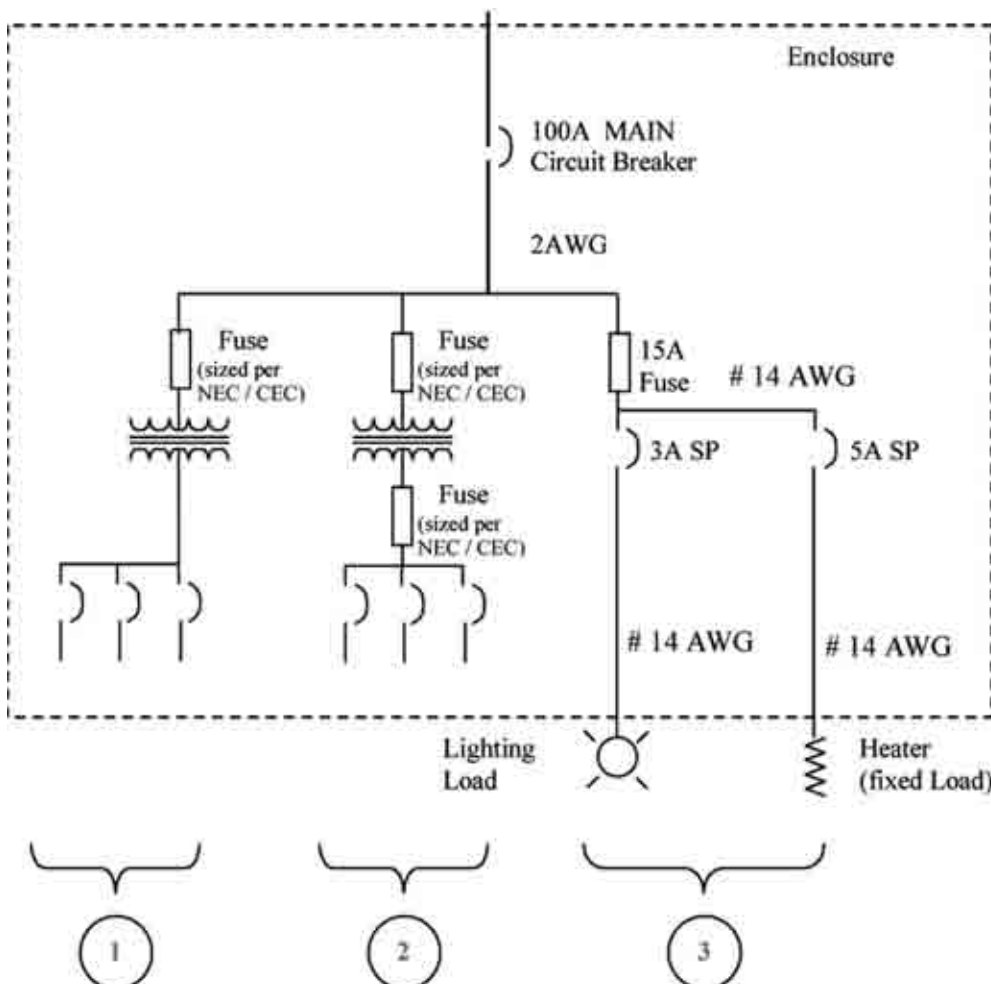


Figure 6

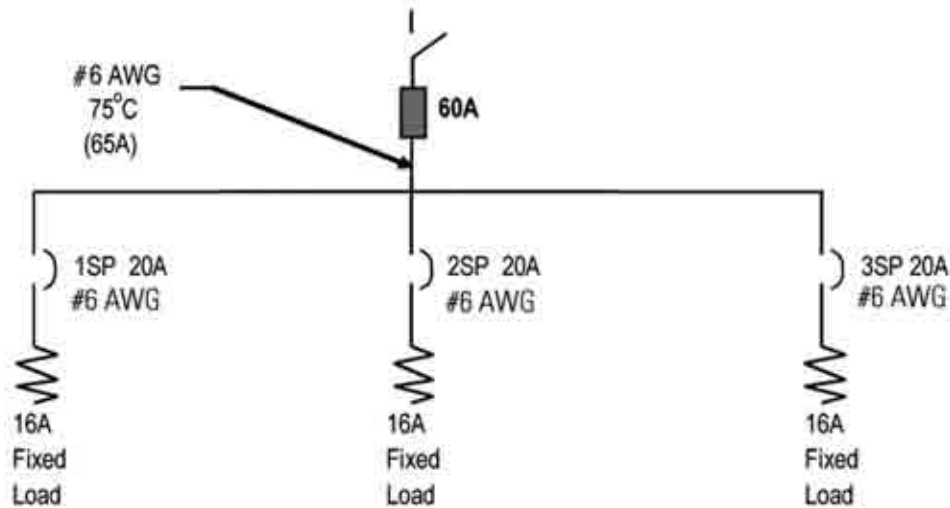


Figure 7

that the maximum over-current protective device should be rated 167% of the primary current.(4) In this case it is 7 A. The NEC requires that the 14 AWG wire be protected at 15 A (except for some special conditions identified in ART240 of the code), so there is extra capacity within the conductor that can be taken advantage of with proper circuit design. The NFPA's primary concern, as outlined in the NEC, is not necessarily component protection, but rather conductor protection and reduction of potential fire damage.

Using a 15 A fuse or circuit breaker will provide protection for the 14 AWG conductor, but the transformer itself could be damaged in the event of a short circuit. Protection at 7 A is still required to reduce the possibility of component damage. In US installations, this protection can be provided with a supple-

mentary protector. If we size the protector at 7 A, we can take advantage of the conductors capacity and could actually have multiple parallel control circuits (or other small loads) protected with the single 15 A primary fuse as shown below. The supplementary protector used in such an installation must carry the U2 short circuit classification (as defined by UL) and be applied within its ratings.

TRANSFORMER SECONDARIES

Application of supplementary protectors on the secondary side of a control transformer is one of the most common uses of UL 1077 devices in US and Canadian installations. Used in this fashion, the supplementary protector can provide protection to the entire control circuit or several

protectors can be used to provide protection to individual control circuit components. The impedance of a transformer effectively limits the fault current that will be seen on the secondary, so supplementary protectors are generally adequate for the levels of energy that could be seen under fault conditions. For example, a 2 kVA transformer, 480V/120V, with 1% impedance has a rated primary current of $2000/480 = 4.2$ A. The secondary current is 16.6 A. The available fault current on the secondary is $2000 \text{ A}/(120\text{V} \times .01) = 1667$ A, which is within the allowable rating of many supplementary protectors. A 5% impedance transformer in the same application would have an AFC of 333 A, which would open up product application to a wider range of supplementary protectors. This example demonstrates that the fault currents that could be seen by the secondary side overcur-

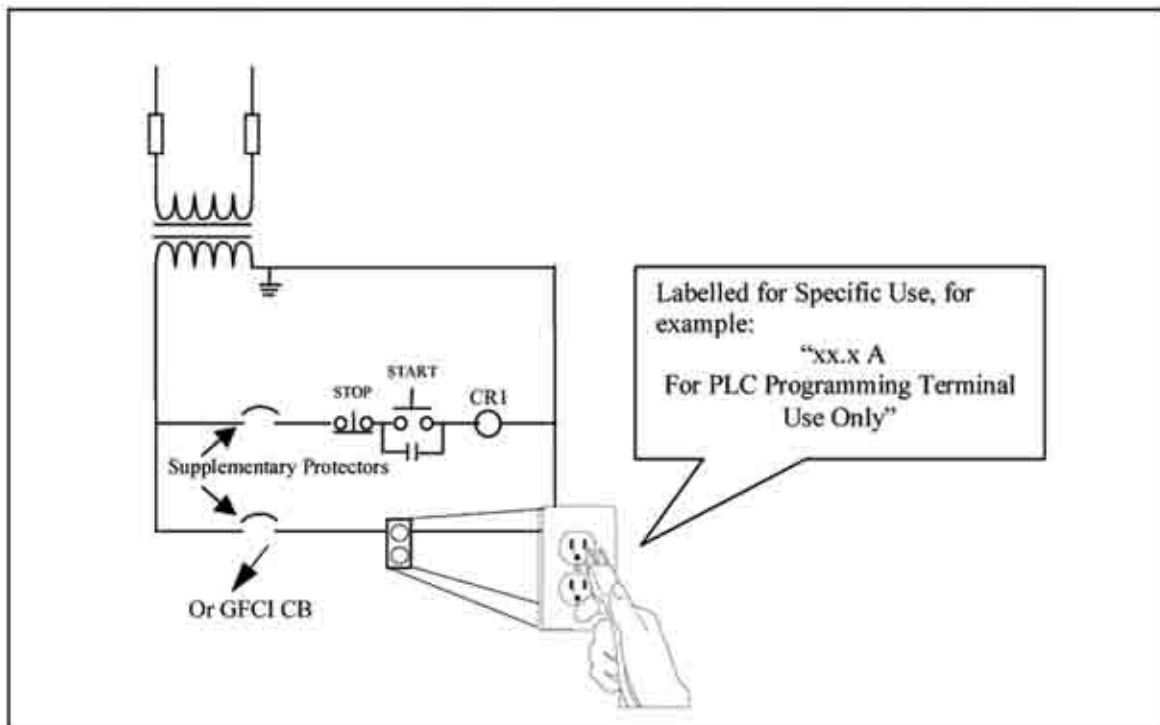


Figure 8

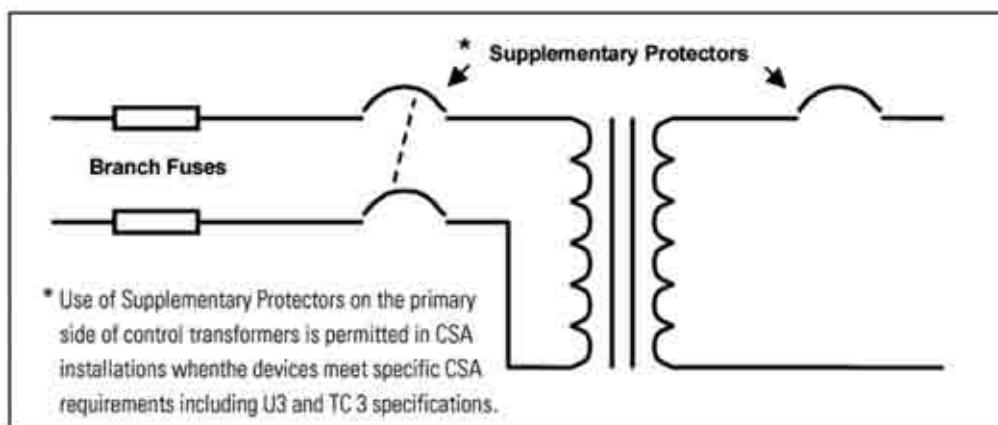


Figure 9

rent device can vary greatly with component selection. But generally in control circuits, the maximum currents seen during a short circuit are at levels suitable for a UL 1077 device to be used.

UL 508A indicates that a control circuit is typically 15-20 A. With a 120V secondary, most applications consider that a 2 kVA transformer is the limit of a control circuit transformer.

POWER TRANSFORMERS

Transformers that are greater than 2kVA are considered power transformers. UL 508A requires that the primary of a Power Transformer have branch circuit protection devices. If a secondary protection device is used, then that device, too, must be branch circuit rated device.

If a motor is included in the secondary of a transformer, then the transformer is to be treated as a power transformer, no matter what the rating of the transformer. However, the application of an enclosure ventilating fan is considered part of the control circuit and is not treated as a motor for purposes of determining whether a transformer is a "control circuit" or a "power" transformer.

MOTOR LOADS

Supplementary protectors are not generally designed or approved for protection of motors in an industrial control environment. When a UL 1077 supplementary protector also holds a motor rated supplementary protector rating, it can be used to provide protection to a motor load. This protection is only supplementary and there must still be upstream fusing provided ahead of the supplementary protector. A key point to note is that a motor rated supplementary protector does not carry a motor disconnect rating. Supplementary protectors are not manual motor con-

trollers and should not be used to switch a motor on or off. The UL 508 rated device is preferred for motor control. UL 508 rated manual motor controllers do carry a motor disconnect rating, and while still requiring upstream fusing, can be used for motor control and overload protection, which enables them to be used as a manual motor starter. Some available devices are rated as a supplementary protector when used in supplementary protection applications and are rated as manual motor controllers when used in manual motor controller applications.

SUMMARY

Circuit protection is an important part of any electrical installation. The wide variety of products and product ratings can make proper component selection a complex task.

Compliance with the applicable local and national codes is necessary to ensure product safety. Understanding the differences between branch circuit protection, supplementary protection, and self-protected products helps to ensure their proper use.

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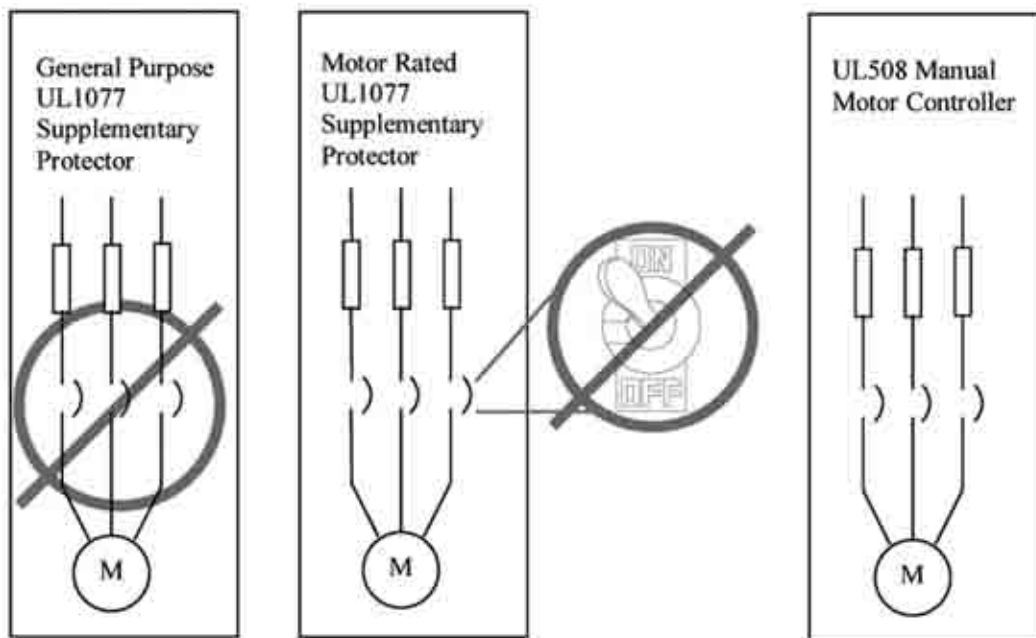


Figure 10

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6) CAN/CSA 22.2 No. 235-M89 (R2001), Supplementary Protectors Copyright 2001 Canadian Standards Association 178 Rexdale Boulevard Rexdale, Ontario M9W1R3

EXPERIENCE USING THE BOUNDARY ELEMENT METHOD IN ELECTROSTATIC COMPUTATIONS AS A FUNDAMENTAL TOOL IN HIGH-VOLTAGE SWITCHGEAR DESIGN

By J. Lopez-Roldan, P. Ozers, Reyrolle; Rolls-Royce T&D; T. Judge, C. Rebizant, Integrated Engineering Software; R. Bosch, J. Munoz, Catalunya Polytech. Univ.

ABSTRACT

We have seen fast development in the computational methods used in all fields of engineering. The possibility of getting rapid and accurate models of High Voltage (HV) Switchgear can reduce considerably the high cost of development testing.

In this article, the Boundary Element Method (BEM) is discussed from an industrial user point of view.

First we analyze the advantages of using the BEM specifically for three-dimensional electrostatic computations.

Two examples are presented. One model is an epoxy rod between two coaxial electrodes in which the electrical field distribution around metal inserts, H.V. shields and along the creepage distance is required. Also shown is the calculation of the change of field configuration after a discharge between the contacts of a disconnecter. In these examples, a three dimensional analysis is necessary because of the geometry of the problem.

These kinds of problems are often found in H.V. engineering and were resolved in the past using much less accurate two-dimensional approximations.

INTRODUCTION

Anybody familiar with the design of H.V. Switchgear can realize the slow progress electrical insulation development has experienced in the last 20 years especially compared with other fields such as electronics.

Nevertheless, the fast development in recent years of computational methods has made it possible to resolve electrostatic problems which, in the past, we had to approximate by rough models and many expensive tests.

These new computational techniques open the door to, if not radical innovation, at least a significant time and cost reduction in the optimization of the H.V. Switchgear design (2).

BOUNDARY ELEMENT METHOD

The Boundary Element Method (BEM) is a numerical method for the solution of boundary value problems. In electrostatics, Maxwell's equations are the governing equations (1). That is, at every point where the surrounding media is continuous:

$$\nabla \times \bar{E} = 0$$

and

$$\nabla \cdot \bar{D} = \rho_v$$

Where $\bar{E}$ is the electric field intensity, $\bar{D}$ is the electric field density defined as $\bar{D} = \epsilon \bar{E}$, and ρ_v is the volume charge density in the region with dielectric constant, ϵ .

On interfaces between dielectrics, the following condition must be satisfied:

$$n \cdot (\bar{D}_1 - \bar{D}_2) = \rho_s$$

Where the normal vector, $\bar{n}$, points from medium (2) into medium (1).

A scalar electric potential, ϕ , can then be defined such that:

$$\bar{E} = -\nabla \phi$$

Using the BEM, material interfaces are replaced with equivalent surface charges and the potential can then be calculated using:

$$\phi(r) = \frac{1}{\epsilon_0} \left\{ \int_v G(r, r') [\rho_v(r') + \rho'_v(r')] dv' + \int_s G(r, r') [\rho_s(r') + \rho'_s(r')] ds' \right\}$$

Where G is the three-dimensional free space Green's function:

$$G(r, r') = \frac{1}{4\pi} \frac{1}{|r - r'|}$$

ρ_v and ρ'_v are the real and equivalent volume charges respectively in each volume, v ; and ρ_s and ρ'_s are the real and equivalent surface charges on each surface s , respectively.

The electric field is computed using a similar expression in which the Green's function is replaced with the gradient of the Green's function.

In the particular case of electrostatic problems, the BEM has some distinct advantages over methods, such as the Finite Element Method (FEM) and Finite Difference Method (FDM), which use differential operators to compute the field.

These advantages include:

BEM requires only the discretisation of dielectric and conductor surfaces, as illustrated in the two-dimensional case of a parallel plate capacitor shown in Figure 1. FEM and FDM require the problem space to be truncated at some arbitrary distance from the model of the device. The entire problem space up to the truncation then requires meshing.

This is illustrated by the FEM mesh for the same parallel plate capacitor in Figure 2. The discretisation of only dielectric and conductor surfaces in the BEM reduces user input and storage requirements for the final solution.

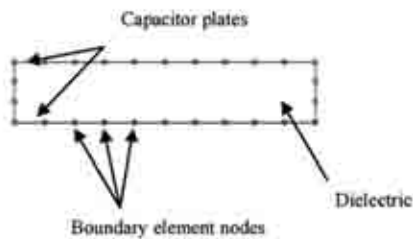


Figure 1. Boundary Element discretisation of a parallel plate capacitor model

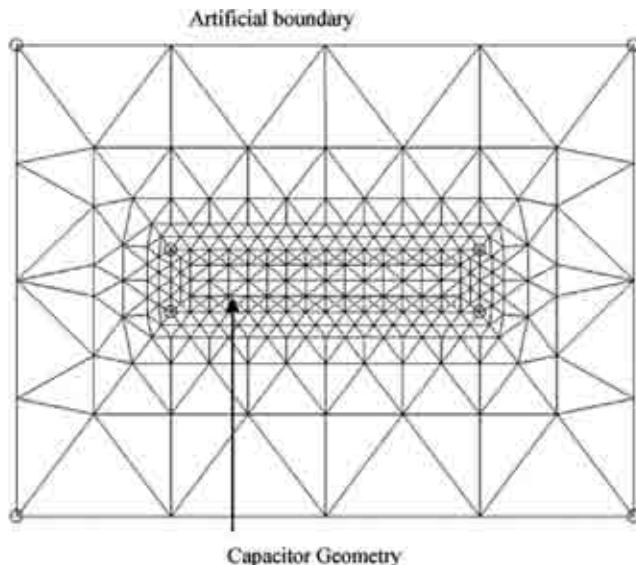


Figure 2. Finite Element mesh of a parallel plate capacitor model

BEM enforces the potential at infinity to be equal to zero.

The fields and potentials can then be computed at any point including the interior of devices and the exterior space to infinity. FEM and FDM require an artificial boundary condition to be placed at the truncation of the problem space.

This usually requires approximating the potential to zero or the derivative of the potential to some value at the truncated

boundary.

There is an inherent smoothing effect when calculating the fields using integration as opposed to differentiation.

Numerical differentiation is much more sensitive to numerical errors in the potential calculation. Smoothing algorithms can be implemented for numerical differentiation but their effectiveness is subject to the basic smoothing operator used.

PRACTICAL APPLICATIONS

In the design of H.V. Switchgear the most common problem to be resolved is to find the electrical field distribution in a complex geometry consisting of insulating materials and metal parts at earth or H.V. potential.

Once the high electric field areas are identified, the geometric parameters may need to be modified and the computation repeated as necessary until the values of the E-field are reduced to a more uniform distribution or level, always giving consideration to the practical construction and economy of the component.

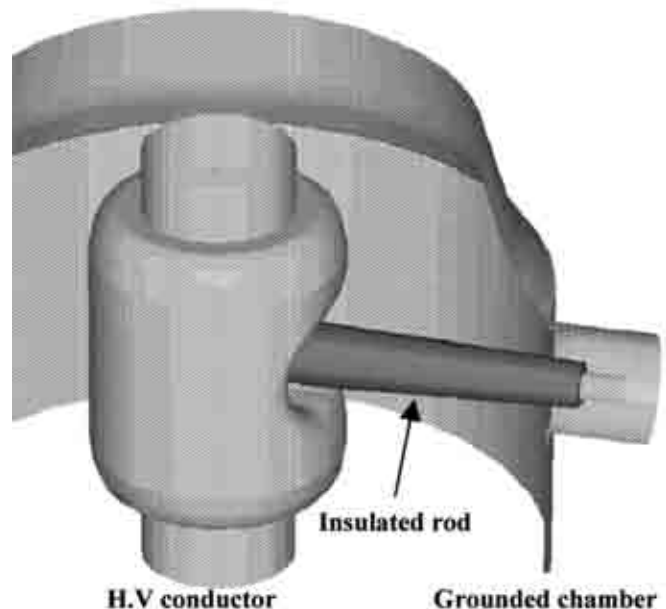


Figure 3. Insulated rod connecting the High voltage conductor and the grounded metal chamber in a Gas Insulated Substation

An example of this kind of application is represented in Figure 3. In a gas insulated substation an epoxy rod penetrates the grounded metal chamber and into the conductor assembly. As the rod interrupts the revolutionary symmetry of the coaxial elements, a 3D approach is necessary.

The insulated rod contains two metal inserts, one each at the earth and H.V. end. In order to design this piece it is necessary to know the maximum value and distribution of the electric field inside the resin to define the value of internal breakdown voltage and hence material suitability and along the outer surface of the resin to define the flashover voltage along the surface between the H.V. conductor and the grounded chamber.

The geometry of the problem is divided into 5000 boundary elements. Figure 4 shows the element distribution around the electrodes and the external surface of the epoxy rod.

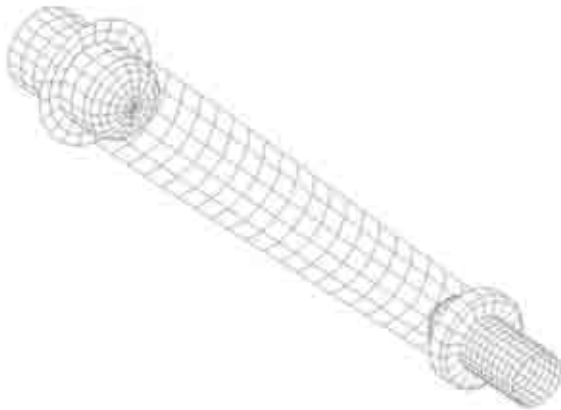


Figure 4. Boundary elements distribution around the embedded electrodes and the external surface of the insulated rod.

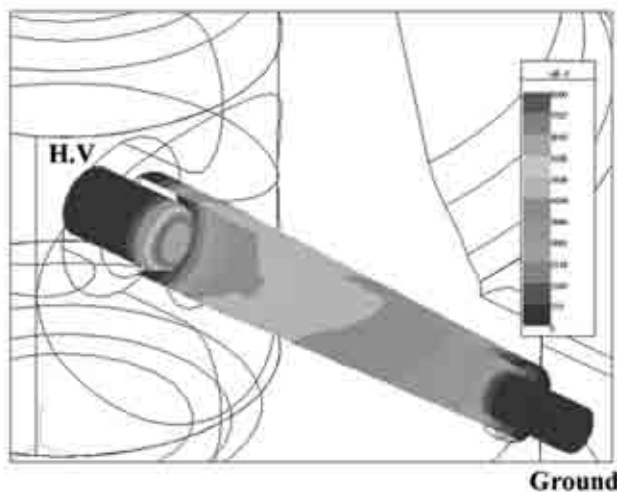


Figure 5. Electric field distribution (modulus) on the surface of contact between the epoxy resin and the embedded electrodes and on the external surface of the insulated rod.

The results of the electrical stress analysis appear in Figure 5.

It shows how the maximum internal stress in the epoxy resin is placed, as would be predicted, on the curvature radius of the H.V. electrode. The junction of the rod and, the H.V. conductor is well shielded and shows low field values and consequently the maximum field on the rod surface is situated more central to the length.

Once the field distribution is known, changes in geometry can be made if allowed by other manufacturing exigencies. In this case, the curvature radius of the H.V. insert or its position with respect to the H.V. conductor will be modified.

The computation and above process are then repeated until the stresses and distribution are reduced to what is considered an acceptable level.

Most problems encountered in the design of Switchgear are of the type illustrated above. There are also occasions when it is necessary to predict the behaviour of the fields in a device under circumstances that will change the original electrostatic configuration. For example, the accumulation of static charge

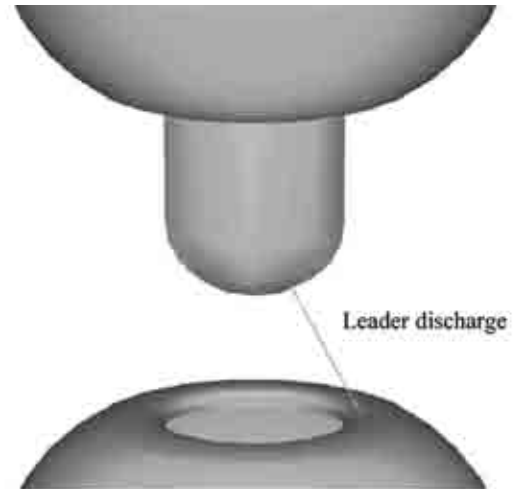


Figure 6. 3D simulation of the moment when a leader discharge bridges two electrical contacts in a GIS disconnector.

on insulators, pollution or transients provoked by discharge.

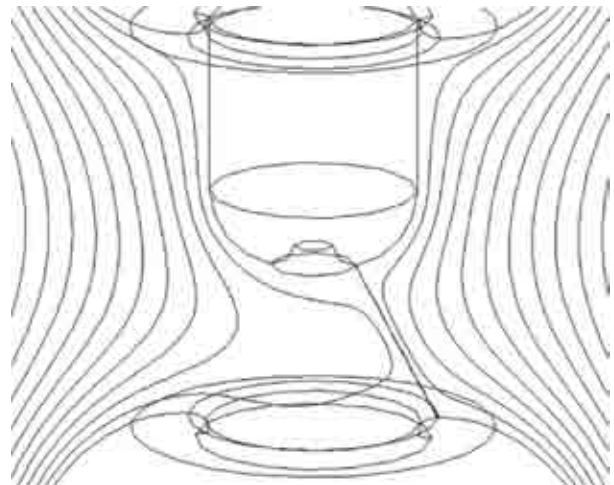


Figure 7. Curves equipotentials in a section of the model represented in figure 4.

As an example, Figure 6 represents a simulation of the moment a discharge leader bridges two disconnector contacts.

The goal is to assess the possibility that the change in the voltage distribution could drive the leader to the enclosure out of the path between the contacts.

The leader becomes represented by a 1 mm diameter conductor between the disconnector contacts. This problem has often been resolved using a 2D calculation (3) but the asymmetry provoked by the discharge needs to be resolved in three dimensions.

Figure 7 illustrates the distribution of the equipotential lines in the plane of the discharge. As well as this, the E-field distribution around the discharge channel can also be examined.

Again, the analysis of this information will facilitate deciding which parameters have to be changed in the next computation (for example to centre the discharge, reduce its length or increase the shield effect of the contacts).

SUMMARY

A BEM-based analysis tool is found to be ideally suitable for electrostatic computations in H.V. Switchgear design.

Several practical examples of common problems in Switchgear have shown how it is possible to get fast and accurate results of electric field distributions. Nevertheless, because it is not the only factor in the design, it is still the engineer who has to analyze the information from the computer and decide which changes to make in the optimization process.

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FUTURE TRENDS IN DEVELOPMENT OF LOW-VOLTAGE VACUUM SWITCHGEAR

By Alexey M. Chaly, Industrial Group Tavrida Electric; John Cunningham, Kelman Ltd. Lissue Industrial

ABSTRACT

A range of new products emerging from recent development in vacuum switching technology is presented. Their technical characteristics, as well as particular benefits providing for customers, are discussed.

1. INTRODUCTION

Since the early '60s, vacuum switching technology has evolved to become the basic technology used in medium-voltage switchgear. However, due to the low cost and technological advances in air break technology, vacuum switching has not significantly penetrated the low-voltage area.

Historically, vacuum heavy-duty contactors represent, in reality, the only market niche where vacuum technology dominates at voltages below 1100V.

However, further development of vacuum technology combined with advanced electronics, sensors and actuators opens application areas that did not previously exist. A few examples of these applications are Rezap, Fusemate and Low-voltage vacuum starter. Details are given on each of these products to depict the amalgamation of vacuum technology with other technologies, to solve particular and important problems below 1100V.

2. REZAP

The Rezap sets out to solve the problem of the management of faults on low-voltage cable networks.

The U.K. distribution system is typical. It is an extensive 415V, radial network that is fed from 11kV open rings circuits with 11kV/415V transformers that feed the cables via

fused distribution panels.

The cables are a mixture of paper/lead and polymeric types and can be up to 50 years old. They carry nominal currents of either 400A or 630A and the level of fault current can vary between 50kA and a few hundred amps. Most faults on the network begin life as intermittent and gradually progress to become permanent.

The pressure that has been applied to the electricity companies has focused attention on the problem of minimizing power outages, especially those due to these intermittent faults.

The Rezap is designed to temporarily replace a fuse in a distribution panel to reenergize a faulted feeder after an overcurrent event. It is essentially a single phase autorecloser with intelligent electronics providing various protection algorithms which emulate the relevant fuse characteristics, thereby allowing intermittent faults to be cleared completely or conditioned to accelerate the onset of a permanent fault and subsequent repair.

Several accessories have also been developed to aid the engineers when on site, such as a Remote Controller permitting the user to walk down the length of the cable while attempting to acoustically locate the fault and also view any damage created. The Rezap Sigma can also locate the transient or intermittent faults and has built in remote communications capability via GSM.

When the fault first appears, it ruptures the distribution fuse and the fault engineer then installs the Rezap in place of the fuse. If the fault is permanent, the Rezap will trip open after it is closed and lock open, however, if the fault is intermittent, the unit will remain closed and will be left installed.

When the fault reappears,

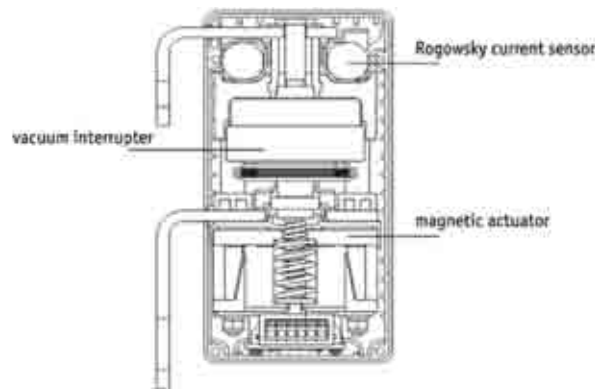


Fig.1. Structure of low voltage vacuum switch used in the Rezap

<i>Rezap parameters</i>	
Rated voltage, V	415
Rated current, A	400 (630 optional)
Rated breaking current, kA	16
Max fault making capacity, kA rms	35
Interrupting life, CO operations	
-at rated current	10 000
-at rated breaking current	50
Weight*, kg	10
Dimensions*, mm	360 x 280 x 140

* these parameters relate to complete Rezap assembly including control electronics

the Rezap will open in order to clear the fault and then reclose in order to restore the supply. The position of the fault will have been automatically located and the result communicated to the Operations Centre, or the local office (Rezap Sigma).

The Rezap is a central tool used by all of the UK electricity companies in order to control and manage cable faults.

3. FUSEMATE

The Fusemate was designed to minimize the risk of personal injury when replacing an LV Fuse. Although this is normally a straightforward procedure, it can occasionally be extremely hazardous, especially if there is a severe fault still present on the circuit. The danger is often amplified by the physical position of the fuse, for example, when replacing fuses in restricted areas such as link-boxes or on a pole-mounted holder. The Fusemate eliminates much of the inherent hazards by permitting the operator to complete the faulted circuit and test the current flow from a safe distance using remote control.

It has a vacuum bottle in series with a built-in fuse and can be fitted directly onto the fuse stalks of a distribution panel. It has microprocessor control electronics and is housed in a tough, polycarbonate body that has high insulation properties.

After it has been installed, it can be closed remotely and will trip open if the fault is still on the system, giving a measure of the fault current. The device is recommended by the Government health and safety department and approximately 3000 are now in service in the UK.

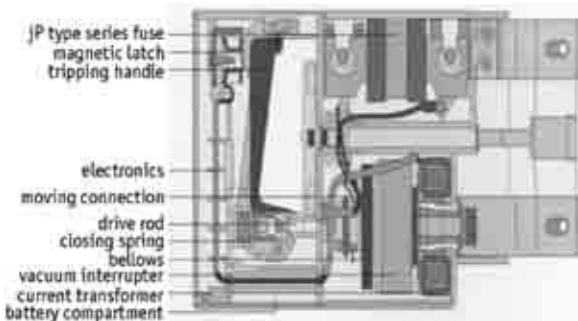


Fig. 2. Fusemate structure

Fusemate parameters

Rated voltage, V	415
Rated current (during 5min), A	400
Rated breaking current (manual operation), A	2,000
Mechanical life, CO operations	10,000
Weight, kg	2
Dimensions, mm	300 x 150 x 85

4. MOTOR STARTER

The traditional motor starter consists of a vacuum contactor, current and voltage transformers and a protection relay

installed in a metal or polymeric housing providing the required degree of protection against external objects. The housing is also equipped with the relevant control and indication facilities: pushbuttons, lamps, etc.

Motor starters can provide complex motor protection, control and indication features. The same functionality can be achieved with the aid of the newly developed VS/TEL-1-400 motor starter representing a mono-block including miniaturized vacuum interrupters, magnetic actuator, current and voltage sensors and a microprocessor-based control unit. The general layout of VS/TEL-1-400 is presented in the figure below.

The protection functionality includes overcurrent, sensitive earth fault, undervoltage, loss of supply, loss of load, broken wire, thermal and other features necessary to provide complex motor protection. Built in RS232 and RS485 ports allow control of the starter via an external computer or SCADA. Built-in man-machine interface also supports basic control and indication functions. The starter also provides fault and load monitoring that permits it to be used as a "point of automation" for industrial networks. The application of the magnetic actuator, instead of the traditional solenoid, makes the starter insensitive to voltage dips that normally occur when starting large motors. The size and weight of the starter are approximately 5 times less than for conventional devices with comparable functionality.

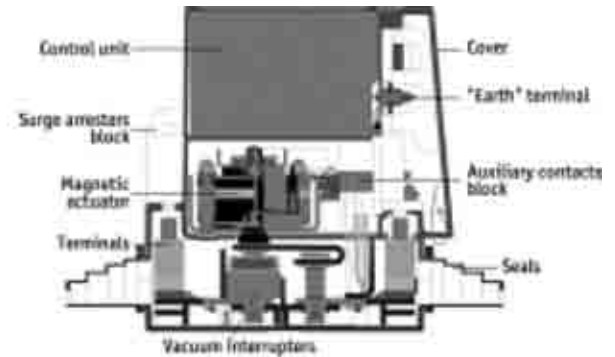


Fig.3. Motor starter structure

Motor starter parameters

Rated voltage, V	1100
Rated current, A	400
Standard duties	AC3, AC4
Degree of protection	IP40
Weight, kg	9.0
Dimensions, mm	190x235x250

5. CONCLUSION

Though vacuum switching devices are barely competitive with conventional air break switches in the majority of standard low-voltage applications, the combination of the advanced vacuum technology with sensitive control electronics and actuators creates new opportunities in a wider range of applications.

With the advent of these emerging market areas, the potential for vacuum to expand even further seems very positive.

NOVEL APPROACH FOR INSULATING MEDIUM VOLTAGE RECLOSERS

By Alexey Chaly, Sergey Benzoruk, Sevastopol, Ukraine

INTRODUCTION

At present the following media are used as insulation in medium-voltage reclosers:

- air
- oil
- SF₆
- solid dielectric

Air and oil can be considered obsolete for pole-top equipment due to the large dimensions and weights required. Oil is also considered to be an environmental risk. Therefore, modern pole top switchgear is generally either SF₆ or solidly insulated.

Both systems have advantages and disadvantages. SF₆ provides more design flexibility, particularly when designing dead tank type switchgear. Dead tanks are attractive for utilities because they allow voltage sensing to be incorporated into all six bushings. As a result, they can fully support modern applications such as ring lines and embedded generation.

In recent years, the use of SF₆ in switchgear design has become the subject of increasingly serious environmental concern. In particular, SF₆ insulated switchgear requires special handling and disposal methods which creates additional problems and expenses for utilities when considered from a total lifecycle standpoint. It is also necessary to continually monitor SF₆ levels within the device. This requirement contradicts the modern approach of reducing service costs by designing maintenance free switchgear. Finally, SF₆ switchgear must have a tank design capable of withstanding pressure differences caused by temperature variations. This can substantially increase the weight of switchgear.

Solidly insulated reclosers were developed during the 1990s as a competitive response to the problems affecting SF₆ switchgear. These reclosers are based upon the application of epoxy material with good track resistance, being used simultaneously as both a mechanical support structure as well as insulation. This method avoids the disadvantages related to SF₆ switchgear (monitoring of insulation consistency is not required, environmental hazard does not exist).

One problem related to this approach is the limited design flexibility. In particular, implementing voltage sensing from both recloser sides becomes impossible. This shortcoming creates extra expense for customers using this equipment in reconfigurable lines as it requires the installation of additional metering voltage transformers.

Another problem is related to a lower track erosion resistance when compared with dead tank designs utilizing bushings covered with silicon rubber. This feature prohibits the use of solidly insulated switchgear in areas where high pollution is an issue.

Finally, the solid dielectric material is subjected to permanent electrical stresses that may cause aging damage if the insulating material has minor porous imperfections after manu-

facturing.

Therefore, the manufacturing technology must be very precise and stable to avoid electrical puncture problems during the product's lifetime.

In the mid'90s Tavrida Electric undertook a research and development project aimed at creating a novel insulation system that would combine the advantages of the insulation systems mentioned above, while simultaneously avoiding their shortcomings.

COMBINED INSULATION

It is well known that breakdown in air occurs when an electrical field exceeds a critical strength of 2.4kV/mm. This value seems high enough, as it should allow a recloser with a 125kV BIL level to provide the required dielectric strength with an air gap of just 52mm.

For real designs however, we have to consider the non-even distribution of an electrical field, i.e. its enhancement in particular weak points.

For example, if two balls with a diameter of 10mm are separated by 100mm the enhancement factor will be 5.4 as shown in Figure 1. For real designs, this factor is even higher, generally scattering between 4 and 20.

Multiplying the minimum contact gap on the enhancement factor, we end up with a required clearance of 200-300mm that makes the design of air insulated dead tank reclosers difficult.

It is possible to substantially improve the characteristics of the insulation system presented in Figure 1 with a slight modification.

Imagine that we place a piece of paper between the balls shown in Figure 1. The dielectric strength of the paper itself is very low (generally <1kV) and has virtually no effect on the distribution of the electrical field because it is too thin when compared with the distance between the balls. So, one could expect that inserting the paper barrier would not noticeably change the dielectric strength. In actual fact, the dielectric strength grows substantially - many times compared with the dielectric strength of the paper. The resultant dielectric strength of the system turns out to be higher than the sum of the dielectric strengths of air and the insulating barrier. Looks like magic - and it is - but the name of this magician is physics.

Let's call this the "effect of combined insulation" and try to understand its background. As the paper barrier cannot noticeably change the electric field, discharge will start when the critical electric strength is exceeded, i.e. at the same level as in the air insulated system presented in Figure 1.

Let's assume it starts from the upper electrode.

A discharge channel appears and heads towards the opposite (lower) electrode. The front edge of this channel carries the potential of the upper electrode, therefore reducing the

dielectric gap during its movement. The insulation system is subjected to positive feedback – the further the discharge propagates, the lower the dielectric gap is and, consequently, the higher the electric field. It seems that nothing can stop it.



Figure 1: Distribution of electrical field between two balls. Electrical strength is presented in relative values, i.e. equals enhancement factor

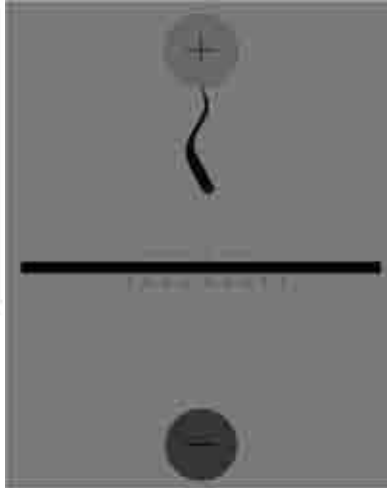


Figure 2: Effect of combined insulation

However, this discharge has one weak point – it needs to merge new air molecules into itself for propagation. These molecules are heated to the high temperatures existing on the front edge of the discharge and ionized – therefore creating the necessary charge for discharge propagation. When the discharge approaches the barrier, it does not find new molecules to be ionized, and decays.

Does this mean combined insulation is capable of withstanding any electrical stress? Certainly not. When the discharge approaches the barrier, it is getting polarized as shown in Figure 2. If the electrical field in the barrier exceeds the critical value, it breaks down and the discharge punctures the insulation.

The voltage applied to the barrier during this process is much lower than the total breakdown voltage. This fact explains the effect of combined insulation. It is interesting to note that in any system utilizing this effect, the barrier material is permanently subjected to very low electrical stresses. This follows from the higher dielectric permittivity of the barrier, pushing the electrical field to the outside. Combined insulation is, therefore, exceptionally reliable due to it not being subject to aging. The effect of combined insulation described above is widely used in electro-technical equipment. For example, insulating barriers between the poles of a circuit breaker is one typical application of this effect.

INSULATION SYSTEM OF OSM RECLOSER

To get an idea of the OSM recloser's combined insulation, imagine a dielectric barrier between all live parts and between live parts and dead tank, extended and shaped in a way to avoid flashover. This insulation system is protected by International Application PCT/RU98/00209 and is illustrated in Figure 3.

Although at first glance this system seems simple, it has consumed a lot of R&D effort by Tavrida Electric scientists and engineers, simulating electrical fields and stresses in the air, solid insulation and rubber joints, and optimizing the insulation design to achieve the highest reliability.

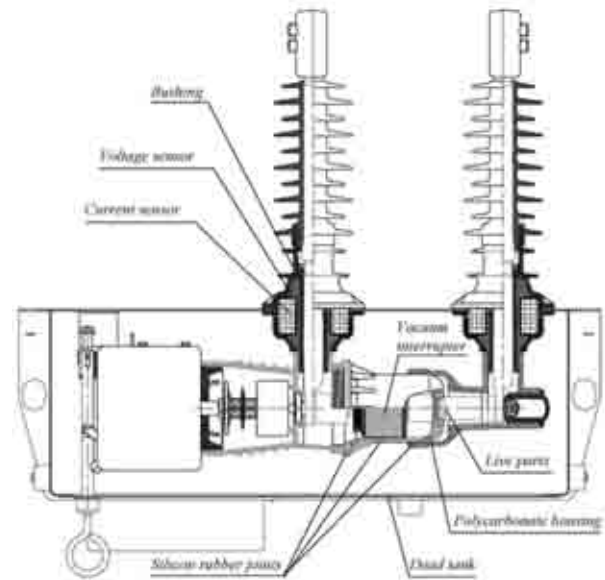


Figure 3: General arrangement view of the outdoor switching module

Two key technologies are used to manufacture the components used in this insulation system: polymers produced with the aid of injection moulding and silicon rubber produced with the aid of hot pressing. Polymers create the mechanical support structure, while silicone rubber is used for joints and external insulation.

Both technologies are not susceptible to the creation of porous imperfections as high pressure is involved in both cases.

CONCLUSION

This novel insulation system developed for medium voltage reclosers is based on the effect of combined insulation. It presents an effective alternative to SF6 and solid-



Figure 4: Simulation of electrical fields

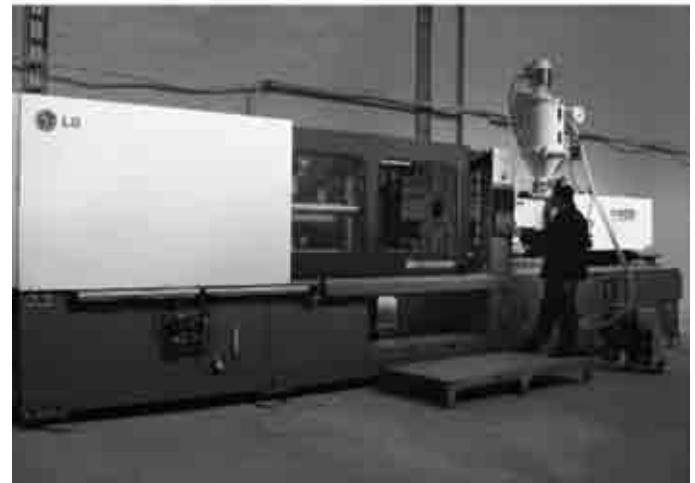


Figure 5: Injection moulding of the polycarbonate Insulators

ly insulated switchgear designs. The positive aspects of both systems are combined to provide the design flexibility offered by SF6 insulated switchgear with the environmental advantages of solidly insulated switchgear while, eliminating the shortcomings of these insulation systems.

EXPERIENCE WITH INFRARED LEAK DETECTION ON FPL SWITCHGEAR

By Dave Keith, Field Service Manager, Roberts Transformer; John Fischer, Project Manager, FP&L
Tom McRae, President, Laser Imaging Systems

INTRODUCTION:

Sulfur hexafluoride (SF₆) is an excellent dielectric gas that is used extensively in high-voltage power equipment. It is chemically inert, nonflammable, nontoxic, and non-corrosive under normal conditions. The power industry is a major user of this gas.

ENVIRONMENTAL:

Studies have found SF₆ 23,900 times more effective at trapping infrared radiation than CO₂.

Its atmospheric lifetime is estimated at 3,200 years. At the 1997 Kyoto Japan summit, SF₆ was among the six greenhouse gases targeted for emissions reduction. The Environmental Protection Agency (EPA) has classified it as a "greenhouse gas". As such, EPA is interested in controlling SF₆ release to the atmosphere and promoting competent SF₆ management.

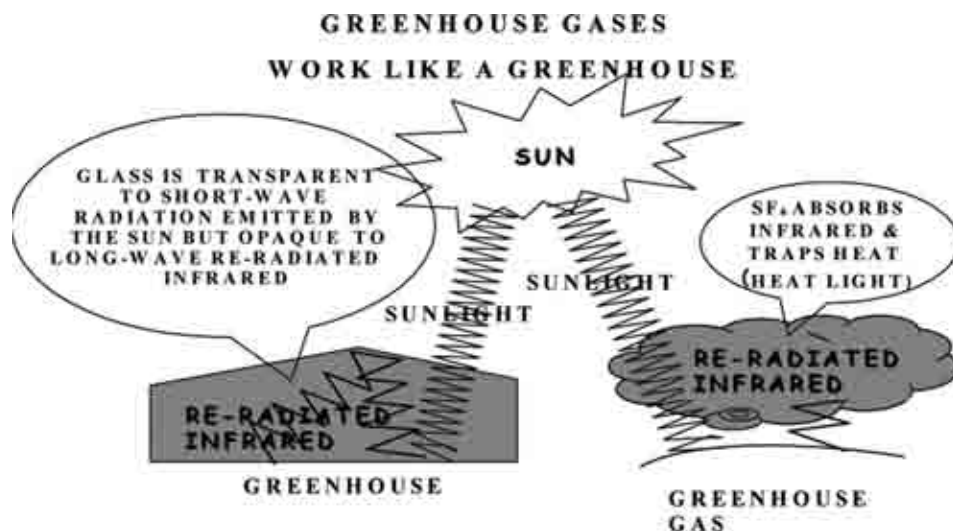
EPA has joined in "SF₆ Emissions Reduction Partnerships" with many of the major U.S. utility companies. A memorandum of understanding (MOU) is drawn up between the EPA and the utility. Partnership requirements include:

- Maintaining ACCURATE INVENTORY OF SF₆
- MONITORING and REDUCING the OVERALL SF₆ LEAK RATE
- Implementation of SF₆ RECYCLING
- Tightly MANAGING the use of SF₆
- Yearly reporting of SF₆ EMISSIONS

GREENHOUSE EFFECTS:

High temperatures such as those found on the sun produce short-wave radiation. A small percentage of this energy hits Earth. This radiation is absorbed; some of it is converted to heat and re-radiated as long-wavelength radiation in the form of infrared radiation (heat light).

In a greenhouse, glass is fairly transparent to short waves, but to longer waves it tends to be opaque. Thus, the inside of a greenhouse warms because of the trapped infrared. SF₆ tends to absorb and trap infrared just as in a greenhouse; in this case, the



heat warms the atmosphere.

CURRENT SITUATION:

To comply with the Partnership, utilities are faced with two primary decisions: How to effectively manage and document the use of SF₆ on the system, and how to effectively detect SF₆ leaks. To answer these questions, FPL did extensive analysis.

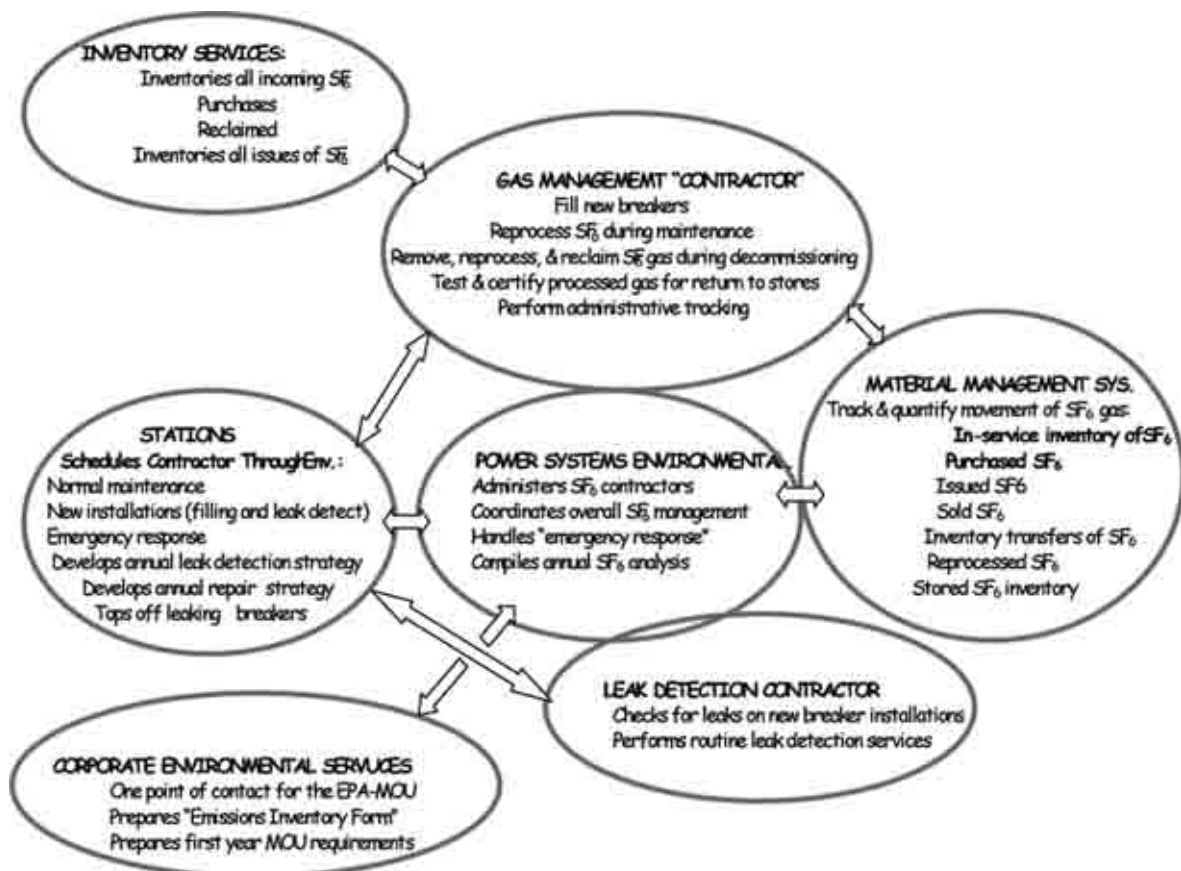
ANALYSIS:

Economic analysis indicated that outsourcing both SF₆ management and leak detection was cost-effective. A management interaction diagram was then created to aid in developing structures, procedures, and bid specifications.

SF₆ LEAK DETECTION:

In the area of leak detection, "Corporate Philosophy" was NEGOTIATED between departments. Agreement was reached on the following:

- All new breakers will be leak checked after installation.
- The existing population of SF₆ breakers will be periodically checked.
- Equipment needing periodic filling will be documented and leak checked.
- Permanent fixes are preferred to temporary repairs (epox-



ies, etc.) where reasonably possible.

- Gas imaging technology will be used.

GAS IMAGING TECHNOLOGY:

Traditional leak detection methods using soap and sniffing equipment require that the breaker be removed from service. Waiting until data are collected on the periodic filling to determine leaking breakers takes time and does not provide information on where the leaks are. Some form of laser-based, remote sensing technology is generally needed if a large equipment population is to be tested in any reasonable time frame.

The technology "chosen" is known as backscatter absorption gas imaging (BAGI). This remote sensing technique is designed for the sole purpose of locating leaks or tracking gas clouds (McRae, 1993). The BAGI technique is a qualitative three-dimensional vapor visualization scheme that makes a normally invisible gas leak "visible" on a standard video display. The image of escaping gas allows the operator to identify the source of the leak and make a fairly accurate determination of its intensity. Gaseous leaks are detected and displayed in real time, but accurate determination of volume is not possible. This was not seen as a problem because the weight of SF₆ gas used to top off leaking breakers is being tracked.

This technology was first developed for the Naval Sea Systems Command at the Lawrence Livermore National Laboratory. The idea was for the protection of sailors during initial surveillance of disabled marine vessels for the presence of toxic or flammable vapors. The system was patented under BAGI technology (US patent #4,555,627) and is marketed under

the trademark "GasVue".

The advantage in using laser imaging systems is multifaceted: the exact location of leaks can be determined; the intensity of a leak is visible; equipment can remain in service while being tested; testing time is greatly reduced; and video documentation of the leaks provides positive evidence.

Figure 1 depicts how a laser camera illuminates the

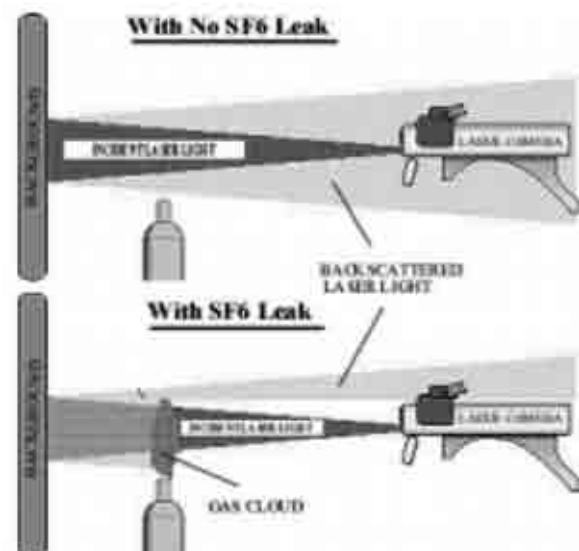


Figure 1

object under inspection, producing an infrared image from the backscattered laser light in much the same way that backscattered sunlight produces an image for a conventional TV camera. The detector in the laser camera is filtered so that it responds primarily to the wavelength of the laser light and ignores essentially all of the background thermal emission. Because there is no SF₆ gas in the top view, the TV image is just of the background objects. However, when SF₆ gas is present, as shown in the bottom view, it absorbs the laser light making the gas appear as a dark cloud. The higher the gas concentration, the greater the absorption, and the darker the gas cloud. In this manner, the normally invisible gas and its origin are visible on the TV monitor.

Figure 2 shows the inspection of an SF₆ circuit breaker with laser system. The infrared image of the area under inspection is shown as the black-and-white inlay. This inlay is the same image that the operator will see in the laser camera's viewfinder. In actual practice, the motion of the leaking gas plume makes the leaking area noticeable. Obviously, this allows for very rapid inspection of the equipment while in-service, and the ability to pinpoint extremely small leaks.

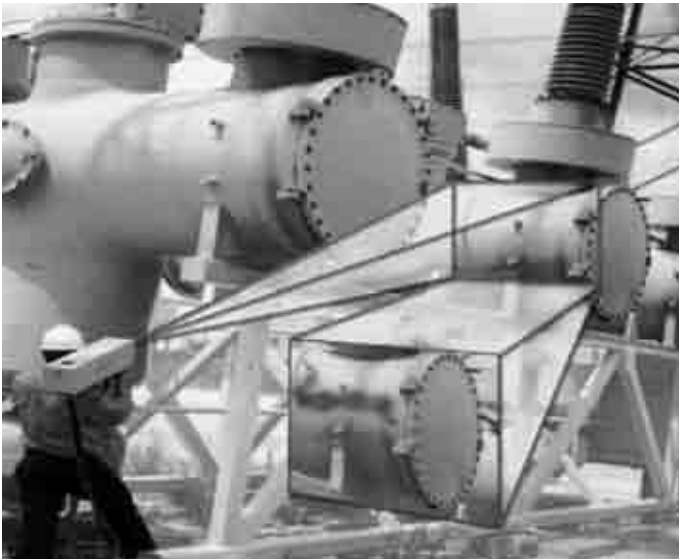


Figure 2

Furthermore, the results can be documented on video.

The technology does have its performance limits. The range of detection is generally between 20 and 30 meters but can be limited by weather (wind in particular). There must be a "reflective or backscattering surface" behind the leak, so it is not possible to visualize a gas plume against the sky. Too much free SF₆ will obscure the leak if the area is indoors and the leaking is so bad that a "high density of SF₆" surrounds the leaking area. The most favorable results have been obtained when the leak source was as close as possible, with low wind speed, and with the escaping gas coming directly at the laser cameras. As a final note, our field results have demonstrated that none of these limits caused insurmountable problems.

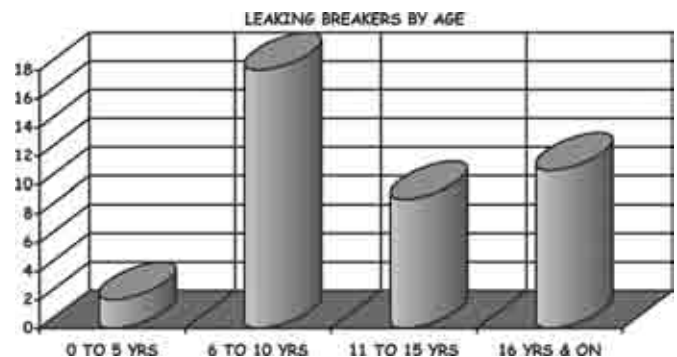
THE EQUIPMENT:

Machines now use CO₂ laser power and video imaging camera equipment. The base unit and camera equipment are bulky, but research is being done to reduce the size (see Figure 3).



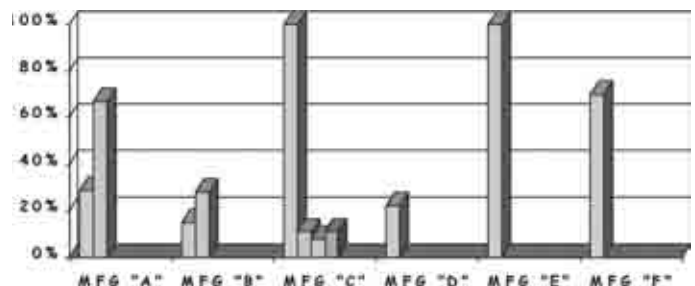
Figure 3

FIELD RESULTS:



AS ANTICIPATED, THE INFRARED LEAK DETECTION PROGRAM HAS PAID OFF:

- Within 4 months of implementation, 460 breakers had been tested.
- 9% (40 breakers) of the breaker population were found with detectable leaks.
- 85% of the leaking breakers were found to have significant leaks and had to be referred to "OPERATIONS" for scheduled repairs.
- 15% of the breaker leaks were minor enough to repair on the spot by the contractor.
- 5% of the leaking breakers were new and still within the warranty period.



WHERE WERE THE LEAKS FOUND?

- 62% of the leaks were found around fittings, piping connections, & gage connections.
- 16% were found around access gaskets.
- 12% were found on bushing seals.
- 5% were found around drive rods.
- 5% were found at welds.

CONCLUSIONS:

- “OUTSOURCING” LEAK DETECTION HAS BEEN ADVANTAGEOUS IN BOTH THE AREAS OF COST AND SPEED OF PROJECT COMPLETION.
- INFRARED LEAK DETECTION HAS ALLOWED FOR IDENTIFICATION OF SF6 LEAKS WHILE EQUIPMENT IS STILL IN-SERVICE
- IN MANY CASES, INFRARED LEAK DETECTION HAS IDENTIFIED LEAKS PREVIOUSLY UNDETECTED USING TRADITIONAL TECHNIQUES.
- RESULTS HAVE BEEN AS ANTICIPATED — GOOD — AND ALL LEAKING BREAKERS HAVE EITHER BEEN REPAIRED, SCHEDULED FOR REPAIR, OR ARE SCHEDULED FOR REPLACEMENT.

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IS YOUR ELECTRICAL SWITCHGEAR SAFE?

By Tony Holliday, Hawk IR International Ltd.

ABSTRACT

In today's infrared community, we talk a great deal about "What is safe?" when it comes to electrical equipment and internal-arc flash. Thermographers generally assume that with the covers and doors closed, the switchgear is in a totally safe work condition. This paper explores the differences in switchgear with respect to internal-arc flash and how this affects the safety of the thermographer. The presentation incorporates a worked example of an internal-arc flash test on a piece of 15kV switchgear incorporating infrared windows, including actual video footage of an arc-flash test occurring.

INTRODUCTION

Infrared thermography of electrical switchgear is a well-known and accepted predictive maintenance technique. Working with any kind of live, electrical equipment incorporates an element of risk, but how does this risk manifest itself in relation to arc-flash and infrared thermography? Is our electrical switchgear totally safe?

RECOGNIZING THE FAULT TYPE: BOLTED FAULTS OR ARCING FAULTS?

Today, the infrared community talks a great deal about "arc fault" or "arc flash," but to understand what an arc fault actually is and how it affects switchgear, one must first appreciate the difference between an arc fault and another, albeit less common, occurrence known as a "bolted fault".

A bolted fault is basically a dead

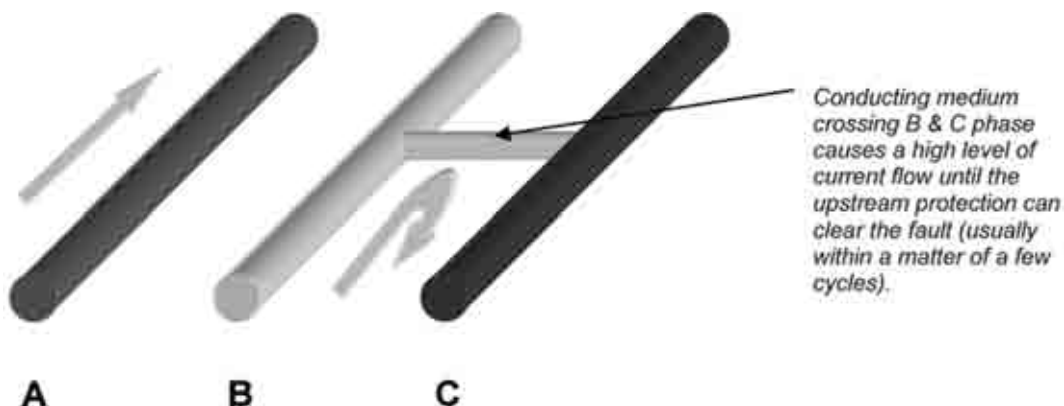


Figure 1. Diagrammatic representation of a bolted fault

short via a highly conductive medium between two different phases or between a phase and Earth conductor. Figure 1 shows a diagrammatic example of a bolted fault situation.

Since the fault current is confined to the relevant conductor, there is usually no energy release outside of the system's conductive path.

As is commonly known, an arcing fault is very dangerous and, as we shall see, quite different from a bolted fault. An arcing fault is also a short circuit between phases or between phase and Earth, but this time the short circuit current flows through the air, rather than through an actual conducting material such as copper.

When an arc fault occurs, temperatures at the fault location increase instantly to over 5000°F (the melting point of copper is 1983°F). Vaporization of internal components resulting

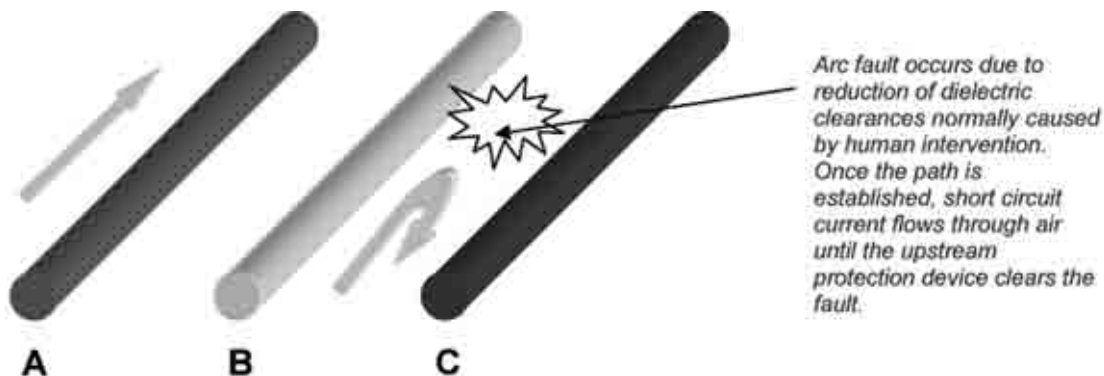


Figure 2. Diagrammatic representation of an arc fault

from this massive temperature increase, along with the super-heated ball of gas, causes an explosive blast that bombards the switchgear with high intensity pressure waves.

Figure 2 shows a diagrammatic example of an arc fault.

Under arc fault conditions, a huge amount of damage is caused to the equipment, and a significant injury hazard is posed to any personnel in the vicinity at the time of the fault.

Arc faults are usually caused by one of the following dynamic interventions into an otherwise static system:

- Dropped tools
- Induced airflow
- Dielectric breakdown of insulation
- Mechanical failure

So, now that we understand the difference between the two fault occurrences, we can look at the switchgear design in relation to them.

HOW DOES THIS AFFECT THE SWITCHGEAR?

Traditionally, switchgear was designed, tested, and rated to withstand the bolted fault current level that could occur, as this is always higher than the arc fault level, due to the lower current impedance of the cross phase conductor in comparison to air. The switchgear was designed to such an extent that the bolted fault current did not exceed the maximum current-carrying capacity of the conductors, and as such, the equipment was not damaged due to the fault.

Note: This current level is called AIC, which stands for “Amps Interrupt Capacity” and can be found on a metal plate on the switchgear that has been type tested against this type of fault occurrence. The designation will show the bolted fault level tested (xxkA) for a time period commensurate with the anticipated cycle time of the upstream interrupter, be it a fuse or a breaker.

However, as we have seen, there is a vast difference between the effects of a bolted fault and an arc fault, and a successful bolted fault type test does not mean that the switchgear can subsequently withstand an arc fault - even at a lower short circuit current level - which is much more violent.

Today, arc-resistant switchgear undergo arc fault type tests in order to satisfy the market that the equipment is indeed safe, should either fault occur at the tested ENERGY LEVEL or less.

Note: It is not correct to associate arc-flash danger solely with voltage. $\text{Energy} = \text{Voltage} \times \text{Current} \times \text{Time}$. So, it is quite possible for the arc flash energy level on 480V equipment to be as high as or higher than on 4160V or 15kV equipment.

See Figure 3 for a fault-tested piece of medium-voltage equipment.

It is important to realize that

arc-resistant switchgear is designed to contain the arc by-products and vent the gases in a safe manner. Protection should include against flying objects, flash burn, escaped hot gases, and glowing particles whether the person is outside the enclosure or inside the adjacent live compartment during maintenance. In order to maintain the arc-resistant protection of the switchgear during operation, all doors and covers must be closed and latched or bolted, while energized.

IS OUR INSTALLED SWITCHGEAR ARC-RESISTANT?

The straight answer is most probably no. Arc-resistant switchgear is expensive due to its construction and certification requirements and, as such, this type of equipment is in the minority in today's workplace. It is a recognized fact that should a fault occur in a non-arc-resistant switchgear, then not only will the equipment be destroyed beyond repair, but it is normal for such explosions to cause covers/doors to become forcibly detached from the equipment.

What this means is that, regardless of whether or not you remove the covers to perform an infrared survey, should an arc fault occur, the cover will be ejected from the cubicle, and the operator will be exposed to the residual fault condition plus the impact from the flying cover.

Figure 4 shows the result of an arc fault explosion in a 4kV starter cubicle.

This is the image that every electrical thermographer must have in their mind BEFORE entering a live, operating switch room. Just because the covers are closed does NOT mean you are safe.

WHERE DO WE GO FROM HERE?

There are a number of points the infrared thermographer needs to remember when dealing with potential arc fault occurrences:

1. Arc faults do not simply happen. They are the result of a change in the static nature of the switchgear.
2. If possible, check the operating schedule of the equipment you will be surveying. If a fault is to occur other than from human intervention, then it is likely to happen when a circuit closes and/or load increases.
3. Ensure that predictive maintenance is carried out regularly to reduce the potential for mechanical failure.
4. Do NOT remove covers or doors to perform the infrared inspection, as this is more likely to cause an arc fault than prevent one.

SUMMARY

With run-to-failure being an unacceptable option, electrical infrared thermography must continue. However, it must be executed in a manner that is as safe as possible, and operators performing the inspections must be trained to understand the dangers and risks associated with the work.

Ultimately, live electrical equipment



Figure 3. Arc-Resistant Switchgear, GE Power/VAC.



Figure 4. 4kV starter cell
Explosion caused due to a failure of the leads feeding the motor. This panel is not arc-resistant and as can be seen, the rear panel was blown completely off.

is extremely dangerous, regardless of whether the covers are removed or not, and it is important that the infrared community not become blasé about the safety requirements needed to carry out infrared thermography on such equipment. The recent high-profile coverage relating to arc fault incidents can only serve us well; however, we need to be careful that we do not fall into the trap of “a little knowledge is a dangerous thing”. There are standards such as NFPA70E in the workplace today to assist not only the thermographer, but all personnel working on live electrical equipment. However, care needs to be taken when applying such standards to your facility. This manuscript has shown that:

1. We dare not assume that, if covers are in place, the thermographer is totally safe. This needs to be addressed in the facility's infrared inspection procedures.
2. Low-voltage systems can have higher incident energy than medium-voltage systems and, as such, it is not sufficient to distinguish between such systems, safety-wise, on voltage alone.
3. In order to reduce the potential for arc fault, we must continue with infrared thermography, but in a manner that does NOT contribute to such a fault occurring.

THE ENVIRONMENTAL BENEFITS OF REMANUFACTURING BEYOND SF6 EMISSION REMEDIATION

By George A. McCracken, Roger Christiansen, Mark Turpin, High-Voltage Switchgear Service, ABB Power T&D

SUMMARY

As scientists and citizens become more concerned with global warming and the impact that “greenhouse gases” are said to have, those companies involved in the transmission and distribution of energy will be required to respond. This paper presents an alternative to a greenhouse gas remediation policy, which focuses solely on the detection of sulfur hexafluoride (SF6) emissions during the manufacturing and operating life of the power circuit breaker. By looking beyond the detection and field resolution of the SF6 leaks to the total life cycle of the breaker, we can have a much larger impact on the issue of global warming. Remanufacturing is a solution that goes beyond detection and provides substantial benefits environmentally, economically and systemically.

INTRODUCTION

Circuit breakers play a vital role in the protection and operation of the electric transmission and distribution system. Circuit breakers interrupt the flow of electrical current in transmission lines for normal switching of transmission circuits, and for emergencies in the event of short circuits on the system.

SF6 has been used for insulation in electrical equipment for more than 40 years. SF6 provides the insulation medium for thousands of power circuit breakers, each having voltage ratings of up to 800 kV, in the electricity supply systems around the world today. In fact, the first high-voltage circuit breaker using SF6 was put in service in 1956 at 115 kV. These first SF6-insulated circuit breakers were dual (or two-pressure) breakers that were derived from the air blast two-pressure circuit breakers. More recently, the single-pressure puffer circuit breaker has evolved as the predominant configuration of high-voltage circuit breaker equipment.

Sulfur hexafluoride’s main characteristics make it very suitable for use in electrical equipment.

These desirable characteristics include:

- High dielectric strength
- Excellent arc-quenching properties
- Good chemical stability
- Nontoxic

SF6 AS A GREENHOUSE GAS

Unfortunately, some of the very characteristics that make SF6 a desirable solution for arc interruption and insulation of electrical equipment also have been found to cause environmental concerns. Sulfur hexafluoride has been characterized by the

U.S. Environmental Protection Agency (EPA) as “a very powerful greenhouse gas” with a global warming potential of 23,900 (EPA Global Warming Site, 2000). Many scientists are concerned about what is being characterized as a global warming trend. These scientists point to an increase in global mean surface temperatures since the late 19th century - and recent data showing that the 20th century’s 10 warmest years all occurred in the last 15 years - as evidence of a dangerous trend. Many are concerned that the rising global temperatures will raise sea levels, change precipitation, and contribute to alteration of forests, crop yields and water supplies (EPA Global Warming Site, 2000).

SF6 LEAKAGE DETECTION EFFORTS

Given the data supporting the assertion that SF6 has some lasting presence in the Earth’s atmosphere and the potential impact of greenhouse gases on the environment, the electric utility industry and those in the electric utility supply chain have taken measures to reduce the escape of SF6. The ABB Group, a global technology company and supplier to the world’s utilities, has reported several measures taken by manufacturers to reduce the level of SF6 escaping into the atmosphere. Marchi, et al. present these measures in a paper titled “Design, Manufacturing, Practice and Information to Minimize SF6 Release From Electric Power Equipment.” These measures include:

- Design for minimizing leakage during operation
- Gas emission monitoring during testing, manufacturing and commissioning
- Gas loss monitoring in service
- Gas recovery and recycling procedures
- Gas recovery from equipment
- SF6 recycling

These measures allow for improved detection of leakage during the life cycle of electrical equipment. Other efforts lead to the elimination of leakage once detected.

REMANUFACTURING AND REMEDIATION OF EMISSIONS

Remanufacturing is a process of rebuilding (and in some cases upgrading) equipment that has previously been utilized in an electrical system. This process (as performed at ABB High-Voltage Switchgear Service) involves disassembly of the breaker to the basic components, comparing those components (and their parts) dimensionally with the original manufacturing specifications, and rebuilding, replacing or machining any parts that demonstrate nonconformities. All components and vessels are

cleaned and restored. The refurbished or replacement components are then reassembled and tested to original equipment specifications. Because the breaker is completely remanufactured, it returns to the customer with the same warranty as was originally granted when the breaker was sold new.

A CASE STUDY: TWO-PRESSURE SF6 BREAKERS

A two-pressure circuit breaker (produced up to 1985) maintains an insulating pressure of 45 psig to 60 psig and an internal arc extinguishing pressure of 240 psig to 280 psig. The device-opening process directs the high-pressure gas across the contacts into the low-pressure system, and a compressor system transfers this gas back into the high-pressure side. The SF6 volume in the two-pressure breakers ranges from 760 lb. for a 242 kV circuit breaker to more than 1,500 lb. for an 800 kV circuit breaker.

There are several thousand two-pressure circuit breakers in service in the electric power transmission grid today, each ranging from 138 kV to 800 kV. One of the unique capabilities of the two-pressure SF6 breakers is the ability to interrupt very high short-circuit currents in the network resulting from faults in the system, such as lightning strikes, power line failure resulting from high wind and snow, and equipment failures. There are more than 100 of these two-pressure breakers installed in critical circuits with short-circuit current ratings of 90 kA throughout the United States. The present single-pressure puffer circuit breakers cannot handle these large currents and, if designed for this duty, would become extremely expensive. Thus, remanufacturing of these circuit breakers is the only viable option.

The two-pressure SF6 breakers have been found to be contributors to SF6 emissions on some systems, leading some observers to assume that the two-pressure design is inherently faulty. In reality, all manufacturers of two-pressure SF6 breakers recognized in the late 1970s that the gasket system in the low-pressure portion of these breakers was resulting in leakage of low-pressure gas to the atmosphere. In time, this gasket material corroded the adjoining metal, resulting in leakage from the low-pressure system. Following the recognition of this issue, all manufacturers implemented the use of seal material with a demonstrated long-term performance.

The recognized corrective action for this early seal system problem involves the machining of all seal surfaces and reassembly using the corrected gasket material. This leak repair process entails the remanufacturing steps previously detailed. In the case of emissions remediation, the testing performed by

ABB in the factory of the remanufactured circuit breaker is more stringent than the tests performed on new equipment. The remanufactured equipment utilizes vessels fabricated from steel plates, as opposed to the use of aluminum castings. Therefore, the leak test technique can be more specialized because it needs to be focused only on the flanged joints and welds. ABB's factory leak testing used in equipment remanufacturing is a process of isolating or 'bagging' each flange/seal joint for a prescribed time period and then testing the 'bagged' volume with a device that will detect a leak rate of 1/60th of 1% per year (by weight). New equipment manufacturing cannot use that 'bagging' technique due to the large surface areas that must be checked. Field experience during many years has shown that the remanufacture techniques are a viable solution to SF6 leakage.

ECONOMIC COMPARISON REFURBISHED VS. NEW BREAKER 362,000 VOLTS		
	Refurbished Breaker 	New Breaker
Prep. /Site Construction Work (using same foundation)	N/A	16 man-days at \$60/hour \$7,680
Engineering	N/A	10 man-days at \$60/hour \$4,800
Disposal of Breaker Carcass	N/A	\$3,000
Refurbishment	\$75,000	N/A
Installation/Test	\$37,500	\$65,000
New Product	N/A	\$200,000 to \$300,000
Spare parts	N/A	\$3,000
Training	N/A	5 Employees at \$1,600 each \$8,000
TOTALS	\$112,500	\$291,480 to \$391,480

OTHER ENVIRONMENTAL BENEFITS OF REMANUFACTURING

Manufacturing any complex product requires the use of a tremendous amount of energy and material. When considering the supply chain and material requirements of power circuit breakers, we find that they can contain more than 9,800 lb. of steel, 7,500 lb. of aluminum, 4,000 lb. of porcelain and 200 lb. of copper. Each of these building blocks of the circuit breaker requires raw material mined from the Earth, and that those raw materials be processed into the finished material required to manufacture the circuit breaker's components. As stated earlier, the two-pressure SF6 breakers require as much as 1,500 lb. of SF6 gas. In processing each of these materials, carbon dioxide (CO2), the most abundant greenhouse gas, is emitted.

Remanufacturing does not require the same material inputs as original manufacturing, therefore eliminating the need for the supply chain. In addition to using lower levels of energy and raw materials, remanufacturing allows for the recycling of the SF6 gas that is already in the circuit breaker. In fact, it is estimated that remanufactured goods conserve the equivalent of 400 trillion Btu of energy per year. Remanufacturing accomplishes this conservation by saving 85% of the energy required to produce a new product (Automotive Parts Rebuilders Association). As an indication of the impact that conservation through remanufacturing is having, the 400 trillion Btu of energy saved is enough to power 6 million passenger vehicles each year (Automotive Parts Rebuilders Association). Finally, an obvious benefit of remanufacturing is the reduction of solid waste that is produced by the disposal of decommissioned electrical equipment and their spare parts inventories.

REMANUFACTURING: THE ECONOMICAL SOLUTION

Having demonstrated the environmental benefits of remanufacturing, we now turn our attention to the economical rewards to the industry. Because remanufacturing does not have the same material requirements as original manufacturing, it is considerably less expensive. The cost of remanufacturing is about 1/3 that of original equipment (see comparison of estimated cost chart, below). In addition to the savings resulting from the material difference, the user will also reap lower site preparation and construction costs, engineering costs, and the elimination of the need for new spare parts inventories. By using equipment familiar to the maintenance crews, retraining costs can be avoided as well. Remanufacturing can also include

upgrading the capabilities of currently operating equipment. These upgrades and life extensions have been conducted on oil circuit breakers as well as circuit breakers containing SF6. By upgrading an oil circuit breaker, the utility gains the benefits mentioned above and continues to enjoy the same or enhanced service from a time-tested technology that does not contribute to the current SF6 emissions issues.

CONCLUSIONS

Although SF6 continues to perform as the best insulator and current interrupter for the electrical transmission and distribution industry, it has raised some environmental concerns.

Remanufacturing is a solution that goes beyond the remediation of SF6 gas emissions by providing the added benefits of reducing CO2 emissions, solid waste generation and raw material usage. Remanufacturing can be accomplished at a fraction of the cost of producing new, while providing quality that rivals that of newly manufactured goods. Finally, the systems, spare parts, and human resource requirements of new technology are avoided when existing technology is remanufactured.

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THE MAGNETICALLY ACTUATED CIRCUIT BREAKER REALITY

By Shannon Soupiset, Development Manager, Andreas Hennecke, Marketing & Communications Manager, ABB Power T&D Company Inc.

ABSTRACT

For decades, medium voltage circuit breakers have used stored energy spring mechanisms to operate moving contacts for the purpose of electrical power interruption. While the electrical interruption technology has significantly improved over the years (from minimum oil to air magnetic to SF6 gas to vacuum), the circuit breaker operating mechanisms have remained largely unchanged. These mechanisms are highly dependent on precise manufacturing and periodic maintenance for even modest reliability. Magnetically actuated circuit breakers offer the first leap forward in mechanism technology in over 50 years. With its simplicity and significantly reduced number of moving parts, this technology offers virtually limitless mechanical endurance with almost no maintenance. It is the technology that meets the demands of the next millennium for highly reliable power distribution.

BACKGROUND

Since its earliest inception, the medium voltage circuit breaker utilized a stored energy spring device.

All mechanical parts move at high energy and velocity during switching operation and are subject to a significant wear over the operating life of the device. Circuit breakers with arc-quenching media such as minimum oil, air, and SF6, require a high amount of stored force for proper switching, especially during fault conditions. The greater the force and energy involved, the greater the stress and wear of the individual mechanism parts. No matter how meticulously the circuit breaker has been designed and manufactured, they still require relatively frequent maintenance. This usually entails periodically replacing the wear parts and lubricating the bearings and other moving/sliding parts.

The introduction of vacuum circuit breakers improved the interruption process substantially. Salient features are: reduced contact travel of about 15 mm, 75% reduction of contact velocity compared to minimum oil type breakers, and small mass of the moving contacts. Accordingly, the modern vacuum circuit breaker requires a significantly smaller, lower energy operating mechanism with significantly reduced wear. Most circuit breakers are required to withstand ten thousand no-load operations as required by the ANSI standard.

Early designs of vacuum interrupters utilized a mechanism similar to that of traditional oil-filled circuit breakers. The introduction of the rotating camshaft was the first redesign in circuit breaker mechanism. Its advantages are optimized contact travel during the closing and interrupting process, gentle handling of the vacuum interrupter bottle and a 60% reduction of moving parts. These benefits resulted in a more reliable product and reduced requirements for maintenance.

Like most other products, there is increasing pressure for further reductions in lifetime costs and increases in performance. For vacuum circuit breakers, this means longer service lives coupled with lower overall operating/maintenance costs. In order to meet this growing demand, ABB embarked on development of an alternative solution to the stored energy spring mechanism. This resulted in the relatively maintenance free, magnetically actuated vacuum circuit breaker newly developed for the ANSI markets.

DESCRIPTION OF OPERATION

Figure 1 shows a side view of the breaker mechanism. In the magnetically actuated vacuum circuit breaker, a single actuator drives a common jackshaft (8). This jackshaft in turn couples the actuator energy to the moving contacts of the vacuum interrupters (2) on all three poles through insulating pushrods (7). The actuator consists of a bistable magnet system, in which switching of the armature (13) to the relative positions are effected by the magnetic field of two electrically excited coils (11 and 14). The jackshaft is basically the only mechanically stressed part. Wear of parts and its associated required maintenance are therefore considerably reduced. The magnetic latching required to hold contacts together during faults is also quite remarkable. Two permanent magnets (12) hold the magnetic armature in one of the two limit positions corresponding to OPEN and CLOSED.

Neither mechanical latching nor a constant electrical current supply is therefore required.

Figure 2 illustrates the functional principle of the actuator. The only moving part is the central armature. The top illustration shows the upper, latched limit position. The magnetic field lines generated by the two permanent magnets are also shown. The magnetic flux is channeled into the upper area of the actuator by the position of the armature, and increases the adherence of the armature to the upper stop. In this condition, there is no power applied to the coil of the actuator, and the actuator can therefore apply its remaining force for any length of time.

The middle illustration shows how the field lines change when current is applied to the lower coil.

The magnetic disadvantage of the larger air gap at the bottom is compensated for by the magnetic advantage of the lower coil, causing field lines in the core assembly to move apart. The latching effect is accordingly diminished, and as the current rises, the armature moves downward. The armature will always seek a position in the field where the magnetic field energy in this system is at its minimum.

In the bottom figure, the armature has reached that position. The coil current and permanent magnet now act together

1. Upper Primary Terminal
2. Vacuum Interrupter
3. Epoxy Potting Compound
4. Lower Primary Terminal
5. Flexible Connector
6. Wipe Springs
7. Insulated Pushrod
8. Jackshaft
9. Stroke Adjustment
10. Position Sensors
11. Close Coil
12. Permanent Magnets
13. Armature
14. Open Coil
15. Manual Opening Actuator
16. Mechanism Enclosure

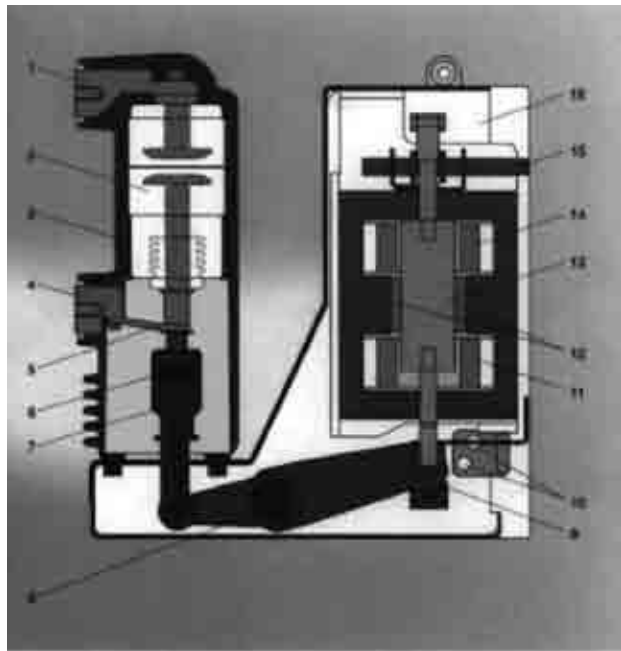


Figure 1: Side View of Magnetically Actuated Circuit Breaker

and produce a very strong force that draws the armature downwards. For safe latching, however, the action of the permanent magnets alone is sufficient, and the current is therefore switched off when the limit position has been reached.

The condition is then a 180° mirror image of the left-hand figure.

Other features of a magnetically actuated circuit breaker significantly reduce auxiliary power requirements and shorten charge time after operation. A single electronic unit controls all input/output functions for the circuit breaker. The auxiliary power required is only a fraction of what a conventional circuit breaker uses. The electrical energy needed for energizing each of the two coils and operation of the breaker is stored in two electrolytic capacitors housed in the circuit breaker.

To recharge the capacitors after operation, the circuit breaker draws less than 1.5A at 120V. The stored energy of the capacitors is capable of performing the standard Open – Close – Open duty cycle common among stored energy spring circuit breakers. Since there are no primary closing springs to charge, the capacitors are charged and ready for operation in less than

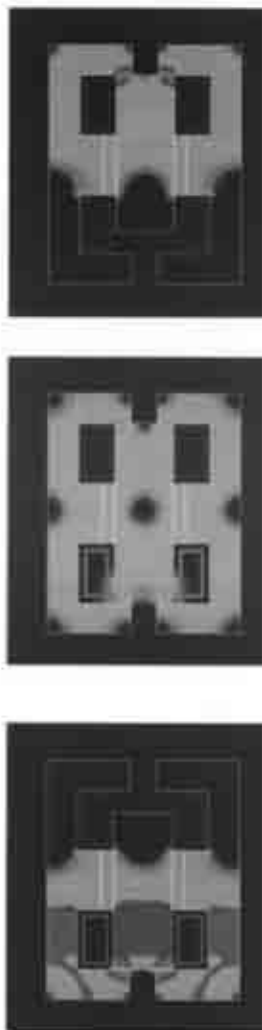


Figure 2: Sequence of Magnetic Operation

2 seconds after a duty cycle operation. The energy stored allows emergency operation in case of control power failure. The AMVAC can be operated for up to 200 seconds following a loss of control voltage.

The breaker can also be opened manually with no control power available utilizing a special manual operation tool (15 of Figure 1). In order to increase the reliability and operational abilities of the magnetically actuated circuit breaker, inductive proximity sensors (10 of Figure 1) are used to detect the OPEN and CLOSED limit positions, thus eliminating the need for standard auxiliary switches.

OVERALL BENEFITS

The intent of the magnetically actuated circuit breaker was to produce a virtually maintenance free component for use in distribution systems with reduced life cycle costs. The number of functional components was minimized, and the remaining components were

optimized for extended lifetimes.

The result was a highly reliable circuit breaker with a lifetime of 100,000 operations.

The magnetic actuator is completely maintenance free over its lifetime. The inductive position sensors have no mechanical interaction with the mechanism, and are therefore also maintenance free. The universal electronic control uses any voltage greater than 80 volts AC or DC, is tested for operational integrity for the extended life of the circuit breaker and consumes only 4W of steady state power. Advanced electrical isolation guarantees EMI proof operation. The unit controls the electrical impulse to the operating coils. Breaker operation can be electronically defeated during racking operation. As an addition, standard mechanical racking interlocks can further enhance operator safety.

New manufacturing technology allows for epoxy molds for all current carrying parts and vacuum interrupters. Epoxy molding eliminates the need for phase barriers and allows reduction of pole center distances. The complete encapsulation also protects the vacuum interrupters from mechanical damage as well as from outside agents like dirt, moisture or animals, which are known to cause high corona discharge or even arc faults. Because of the potting effects of the epoxy, temperatures are equalized across all current carrying parts, making higher continuous currents possible with less conductive materials. The pole is completely maintenance free over its lifetime.

The following table demonstrates the virtually limitless mechanical properties of magnetically actuated technology.

FREQUENTLY ASKED QUESTIONS ABOUT THE MAGNETIC ACTUATORS AND AMVAC CIRCUIT BREAKERS

ARE THE PERMANENT MAGNETS DEPENDENT ON TEMPERATURE?

At an ambient temperature of 120°C, the flux density of Koerdym 280 is reduced only fractions of percent over a 100 year time period. With a standard service life of 30 to 40 years for medium-voltage equipment, safe operation is therefore in no

ANSI Requirement	Minimum Requirements* (Industry Standard)	Magnetically Actuated Capability
No-load mechanical endurance	10,000 no-load operations	100,000 no-load operations
Operations between servicing	2,000 no-load operations	Limited only by environmental conditions
Continuous current switching	1,000 load operations	30,000 load operations

Table 1: Mechanical properties of Circuit Breakers

* These are the maximum endurance requirements by ANSI for breakers rated at less than 15kV rated voltage, less than 31.5kA symmetrical interruption, and less than 2000A continuous current. Endurance requirements for higher voltage, interruption, and continuous current ratings are considerably lower.

way impaired. In addition, the maximum permissible temperature for switchgear under normal operating conditions is 40°C.

DO PERMANENT MAGNETS OR ARMATURE BEARINGS AGE DUE TO PHYSICAL VIBRATION DURING SWITCHING OPERATIONS?

Concerns regarding aging of magnets or bearings have been proven to be unfounded. The AMVAC breaker design has demonstrated 100,000 operations in many tests. UL Laboratories have witnessed testing throughout the development process.

WHAT IS THE RISK OF CORROSION OVER TIME TO THE MATERIAL OF PERMANENT MAGNETS?

The permanent magnets used are of the rare earth magnetic material neodymium-iron-boron. The first magnets made of neodymium-iron-boron were susceptible to corrosion, however the risk of corrosion has been virtually eliminated by the addition of corrosion inhibiting materials to the magnets. The permanent magnets used in the AMVAC circuit breaker are further protected by tin plating.

IS THERE RISK OF CORROSION TO THE LAMINATED CORE?

The laminated core is coated with protective paint resistant to corrosion.

WHAT ARE THE RECYCLING REQUIREMENTS FOR COMPONENTS OF THE CIRCUIT BREAKER?

For reasons of possible environmental pollution, capacitors have to be disposed of as controlled waste. The aluminum electrolyte capacitors utilized in the AMVAC breaker design contain no polychlorinated biphenyls (PCBs) or similar substances that could give rise to dioxins on incineration.

There are no fundamental problems with disposal of encapsulated breaker poles. Disposal requires slightly more work in comparison to standard breaker poles. Where required by law, the interrupter has to be physically broken out of the pole part. The reduction in the number of parts more than compensates for this disadvantage.

WHAT HAPPENS IF THE AUXILIARY VOLTAGE FAILS?

An energy storage device is integrated in the mechanism enclosure. The breaker can be operated electrically for up to 200 seconds after failure of the auxiliary power supply. Thereafter,

the circuit breaker can be opened by the emergency manual operating system.

ARE THERE CONCERNS WITH THE EXPECTED LIFETIME OF THE ELECTRONIC CONTROLLER DUE TO THE LARGE PHYSICAL VIBRATION DURING SWITCHING OPERATIONS?

These concerns have also been demonstrated to be unfounded by the numerous endurance tests completed as part of the development process.

WHAT IS THE ANTICIPATED LIFETIME OF THE COMPONENTS ON THE ELECTRONIC CONTROLLER?

The empirical feedback gained so far from extensive testing indicates a lifetime of over 25 years under normal environmental conditions.

ARE SENSORS MONITORED DURING THE SWITCHING OPERATION?

The sensor logic is included in the self-monitoring system of the electronic controller. The controller will detect an error if a switching command is issued and the sensors do not detect a change in mechanical state.

ARE THERE ANY CONCERNS WITH REGARDS TO PERFORMANCE OVER THE LIFETIME OF THE CAPACITORS?

Progress achieved in the field of capacitor design in recent years provides for sufficiently long service lives. The long service life is enhanced by the fact that the power supply of the AMVAC circuit breaker provides constant DC voltage without AC component. This constitutes ideal electrical conditions for operation of electronics. At 50°C capacitor lifetime is approximately 45 years. The usual life of medium-voltage equipment is thus considerably exceeded.

HOW ARE THE VACUUM INTERRUPTERS REPLACED WHEN NECESSARY?

Since vacuum interrupters of the AMVAC breaker are completely embedded in the pole parts, complete breaker poles have to be replaced. This is usually not required during the lifetime of the equipment except under extreme service conditions.

DOES THE AMVAC CONFORM TO ALL DESIGN SPECIFICATIONS OF THE ADVAC CIRCUIT BREAKER TOO?

The AMVAC circuit breaker will satisfy all in-service requirements and ratings fulfilled by the ADVAC circuit breaker, tried, tested and in service worldwide. Due to the combination of magnetic actuation and encapsulated pole design, a nearly maintenance-free circuit breaker is available for the first time. The familiar reliability of the ADVAC breaker is exceeded by reducing the number of moving parts. The input/output characteristics of the electronic controller will provide controls never before available with standard circuit breakers.

FREQUENTLY ASKED QUESTIONS CONCERNING VACUUM SWITCHING TECHNOLOGY

IS IT POSSIBLE TO CHECK THE INTEGRITY OF A VACUUM INTERRUPTER CHAMBER?

Yes, it is possible to check the integrity of a vacuum interrupter chamber. The circuit breaker is tested with a one minute AC withstand test. If air has entered the interrupter chamber, flashovers occur between contacts. This test is frequently performed prior to commissioning of a circuit breaker and recommended when servicing the breaker. This measure prevents systems from being put into service with circuit breakers in which an interrupter has previously been damaged.

Leakage is usually only caused by physical damage. The epoxy mold protects the vacuum interrupters of an AMVAC circuit breaker significantly reducing the risk of damage.

WHAT ABOUT INSTALLING A PRESSURE SENSOR TO CONTROL THE VACUUM INTERRUPTER?

Permanent sensing of vacuum is technically not possible at this time. Vacuum technology manufacturing is recognized for its inherent high quality. A pressure monitor is not considered necessary.

HOW DOES A VACUUM CIRCUIT BREAKER WITH AN INTERRUPTER CHAMBER CONTAINING AIR OPERATE?

Consider two scenarios with different results:

A single-phase short circuit fault occurs when a phase-to-ground fault occurs in one phase of a solidly grounded system. A sustained arc arises in the compromised interrupter chamber; please refer to the next question for consequences regarding persisting arcs.

Upon interrupting in an ungrounded or inductively grounded system, the flow of current is interrupted, as the two sound interrupters extinguish the arc properly. At 15 kV, the punctured interrupter withstands the phase to phase voltage, with the result that arc through generally does not occur. At higher voltages, flashover between the contacts can occur. The defective phase is not interrupted and a current reflecting the system conditions flows across the contact gap.

DO THE VACUUM INTERRUPTERS ON CIRCUIT BREAKERS EXPLODE WHEN ARCING PERSISTS?

No, vacuum interrupters do not explode.

The sustained arc causes a temperature rise in the interrupter chamber. Only if the fault condition persists for several seconds and only if the arc current is sufficiently high, may the chamber material melt and cause arcing in the circuit breaker compartment. Usually upstream protection will clear the fault condition.

CAN A VACUUM CIRCUIT BREAKER COPE WITH AN EVOLVING FAULT?

An evolving fault occurs when a short circuit current suddenly appears during the interruption of a low current. It is known that minimum oil circuit breakers explode during this relatively rare occurrence.

A vacuum circuit breaker is the only type of breaker that perfectly masters evolving faults, because it does not require the flow of an arc-quenching medium. Only a very small gap between contacts is required in vacuum to extinguish an arc.

ARE HAZARDOUS X-RAYS CREATED DURING SWITCHING WITH ABB VACUUM INTERRUPTERS?

No hazardous X-rays are created during breaker operation. When extremely high voltages are applied, charge carriers in the electrical field are accelerated and can cause radiation when they impact on the electrodes. Tests on the interrupters used in AMVAC circuit breakers have shown that no injurious X-rays appear even at standard test voltages. The permissible limit of 1 $\mu\text{Sv/h}$ is never exceeded.

WHY ARE THERE CURRENTLY NO VACUUM CIRCUIT BREAKERS FOR HIGHER VOLTAGES?

The request for vacuum interruption technology for higher voltages is based on the assumption that what works well for medium voltage must also work well for high voltage. Here are the facts:

Vacuum interrupters with a contact gap of up to approximately 7mm exhibit higher dielectric strength compared to SF₆. Contact gaps of more than 7mm have higher dielectric strength when SF₆ is used as medium.

At 16 mm (corresponding to the distance between contacts in a 36 kV vacuum circuit breaker), the measured dielectric strength is approximately 200 kV. This is slightly higher than the rated lightning impulse withstand voltage of a standard 38 kV breaker. For higher system voltages, therefore, one would have to connect two or more vacuum interrupters in series, something that is done by several manufacturers. Unfortunately, that is not always very economical. It can thus be deduced that the vacuum circuit breaker is economically advantageous up to a rated voltage of 38 kV, but less so above that level. This is why SF₆ circuit breakers are typically used at voltages higher than 72.5 kV.

WHAT ROLE DO VACUUM CIRCUIT BREAKERS CURRENTLY PLAY ON THE WORLD MARKET?

Unfortunately, there are no precise statistics available. Published estimations by ABB and Siemens show that more than 60% of all circuit breakers manufactured are vacuum circuit breakers. In the United States, the market share of vacuum interrupters is greater than 90%.

RACK POWERING OPTIONS FOR HIGH-DENSITY POWER SYSTEMS

By Neil Rasmussen, American Power Conversion

INTRODUCTION

Information Technology (IT) refreshes in the data center and network room typically occurs every 2 to 3 years.

As equipment is changed, the power requirement, the voltage requirement, the redundancy requirement, and the connector requirement often change as well. As rack enclosures have become the standard means for housing and organizing computing and communication systems, the power distribution system for the rack enclosure must adapt to these changing requirements.

Power density predictions for racks in Data Centers have sharply escalated as a result of the high power density of the latest generations of computing equipment. Off-the-shelf IT equipment such as 1-U servers or blade servers can draw 20kW or more in a fully configured rack. This density cannot be supported in a Data Center environment where the average rack is fed by a single 120V 20A power circuit. Twenty of these circuits would be required per-rack to support a 20kW load in a dual-path electrical environment.

The power requirements of modern computing equipment vary as a function of time depending on the computational load. Until the year 2000, this variation was very small and could be ignored for almost all computing and communication systems. However, the implementation of power management technologies into processors and servers began during the year 2000; today the fraction of computing equipment which has a substantial variation in power consumption in response to the computing load is increasing. This variation can be as high as 200% of the baseline power consumption of the equipment. The power distribution system design for a rack enclosure must comprehend this variation.

This article is focused on AC rack power distribution. DC power distribution has a very limited role in the modern high density data center.

This article is limited to a discussion of North American voltage and connector standards. The appropriate rack power distribution strategy is considerably different for the 230V systems, which predominate in most of the world.

HISTORIC MEANS FOR PROVIDING RACK POWER

The most common approach today is to design, engineer, and install power solutions specific to a rack enclosure. Should the requirements for that rack enclosure change, an alternative power solution must be designed, engineered, and installed. While this approach can comprehend any unique power requirement, it involves significant planning, engineering, and rewiring. Rack enclosures are usually fed from a common power distribution panel within the data center or network room. In many instances, this panel cannot be de-energized in order to adapt a rack enclosure(s) power distribution system (i.e. install

another breaker). The result is known as “hot work” and not only introduces a very serious safety hazard, but a high degree of risk of creating a fault in the circuit being worked on and/or dislodging/faulting adjacent wiring circuits. Such errors result in undesirable downtime.

Ideally, the rack enclosure power system would be adaptable to any realistically possible combination of equipment, on demand, without the need to perform any work that would be a hazard to safety or that might adversely affect system availability.

RACK POWERING REQUIREMENTS

The various dimensions of rack enclosure power requirements are summarized in the following sections.

The nature of the requirements is outlined and rational design approaches are summarized.

VOLTAGE REQUIREMENTS

In North America, data centers are provided with both 120V and 208V power. The voltage requirement and supplied power cord of the IT equipment break down approximately as follows:

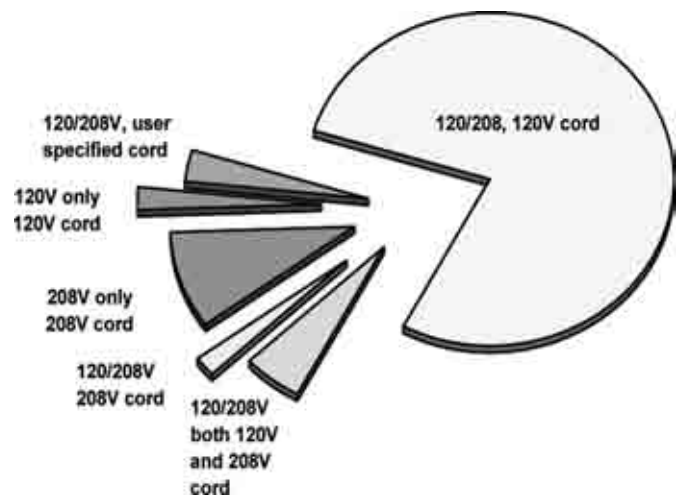


Figure 1 – Voltage requirement and supplied power cord for IT equipment in North America

This complex situation suggests the need for the rack power distribution system to provide both 120V and 208V. However, it is possible to consider using a system restricted to a single voltage, either 120V or 208V.

These two possibilities are discussed below.

The selection of 120V as a single voltage standard for a data center seems most convenient because almost 95% of equipment is provided with a 120V power cord. Unfortunately,

the 5% of equipment that accepts only 208V is often the most important and mission critical equipment, such as large routers and blade servers. Therefore, it is not realistic to design a rack power distribution system based solely on 120V except for very small network rooms.

The selection of 208V as a single voltage standard for a data center assures compatibility with over 97% of equipment, including the most critical equipment. However, the supplied 120V power cords of the majority of the equipment must be replaced by the user with the appropriate 208V cord, requiring that the user keep appropriate replacement cords on-hand. For some equipment it is also necessary to switch the power supply from 120V to 208V operation with a selector switch; the failure to activate this switch on equipment so-equipped can lead to catastrophic failure when powered by 208V. The 3% of equipment that only operates from 120V can be excluded from the data center, because in almost all cases these devices are small accessory equipment that has acceptable and readily available substitutes that will operate on 208V.

Nevertheless, providing 120V in the rack power system can be a very significant convenience, eliminating many plug incompatibilities. For this reason, nearly all existing data centers in North America provide both 120V and 208V and virtually none have standardized on 208V exclusively.

The rack environment is single-phase. There is an insignificant quantity of rack mounted IT equipment manufactured that requires three-phase power (Some brands of blade servers being notable examples).

Occasionally, a pre-configured OEM rack enclosure is wired using an internal power distribution unit (PDU) that takes in three-phase power and provides three branches of single-phase power to the single-phase IT loads. It is important to note that these IT loads are actually single-phase. Despite the absence of three-phase loads, there is a good case to be made that three-phase power should be distributed to racks as will be shown later in this paper. One key benefit of providing 3-phase to the rack is that an inherent property of 3-phase distribution is the ability to power 120V and 208V loads from the same branch circuit.

POWER REQUIREMENTS

Power densities within the rack enclosure can vary greatly dependent upon the equipment installed. In the extreme low-load case, a rack enclosure may only have passive patch panels or a few internetworking switches with a power draw of <100W. In the extreme high load case, a rack enclosure may be completely filled with high-density servers for a total load of 20kW or more.

In addition to supplying the total rack power require-

ment, the rack power system must also be able to provide the required power to an individual device. Sending multiple branch circuits to a rack may appear to provide the total power requirement, but the power requirement of an individual large load may exceed the capability of any of the branches. For example, sending any number of 20A branch circuits to a rack where a single piece of equipment requires 30A is insufficient. Another example is a blade chassis with a 30A plug that may be initially populated with only a few blades and use 5A on a 30A circuit. Some customers may think they can put multiple blade chassis' on a single 30A circuit, but as they populate the chassis they overload the circuit. In cases like these, it is recommended that only one load device be attached to each branch circuit.

The appropriate design value for average rack power level is a subject of considerable controversy. An APC survey of usage patterns in corporate data centers, network rooms, and communication rooms identified the distribution of per-rack power consumption shown in Figure 2. This graph shows the frequency of occurrence of racks configured to different power levels. The frequency of occurrence goes down with increasing power level. 95% of racks draw power below 6.5kW.

A projection of usage in the year 2008 (based on technology / client trends) is also shown in Figure 2. This indicates that the average power per rack is increasing over time. It is possible to configure IT equipment today that would exceed a 20kW per-rack power requirement if fully populated into a rack enclosure. While possible to achieve, we did not find this occurrence to be frequent in real-world installations. The data collected indicates that the average power density per rack enclosure will rise sig-

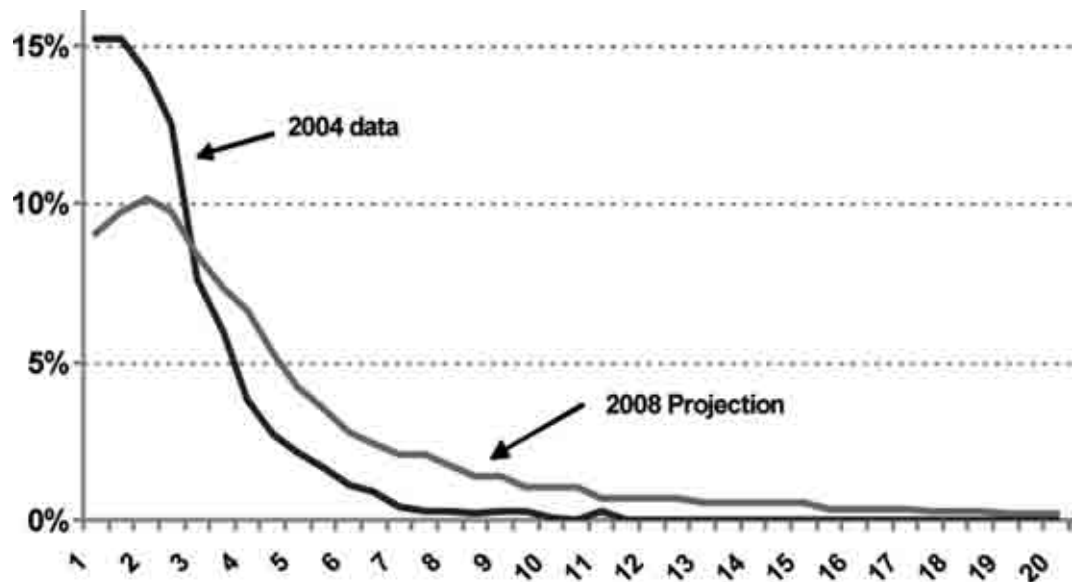


Figure 2 – Per-rack power consumption frequency distribution

nificantly. However, power densities >6kW will still remain a small fraction of the installed base.

An analysis of the underlying data of the distribution of rack power indicates the following:

- The very low loads are mainly rack enclosures with wiring patch panels, switches, and hubs
- Loads in the 1kW range are mainly sparsely populated rack enclosures
- Loads in the 2-3kW range are mainly rack enclosures

that are populated with typical equipment but with significant unfilled rack space

- Loads in the 5kW range are partially loaded with 1U servers, or contain a mix of technologies
- Loads in the 7kW + range are extremely rare but, according to customers, are going to become more common with the recent density increases resulting from server technology advancements.

The mean value for rack power consumption in corporate computing environments is around 1.5kW.

However, organizations were found to have variable mean power consumption within their overall rack enclosure environment. These organizations take different approaches as to how much equipment they pack into a rack enclosure. Some leave large amounts of space within the rack enclosure unused, while others may pack equipment as tightly as possible. Therefore, the market-wide mean rack power consumption is not necessarily a good predictor of average rack power consumption within an organization.

The electrical circuits between the last over-current protector and the equipment are called “branch circuits”.

It is important to understand that electrical codes specify that the branch circuit rating of a circuit is dictated by the load and cannot be arbitrarily chosen by the user. In the USA, virtually all branch circuits in rack enclosures are rated for 20A1.

The maximum power available to the rack enclosure depends on the number and type of branch circuits provided within the rack enclosure. Clearly, the number of branch circuits

equipment from it and moving it to another rack enclosure. However, the consequence is that a reduction in space utilization occurs. For an occasional rack enclosure this is not a serious problem.

An adaptable rack enclosure power system would be able to provide enough power to supply the maximum anticipated load to any rack enclosure at any time without re-engineering the power system. In North America three 120V branch circuits per rack enclosure or two 208V branch circuits is a practical design baseline, with the ability to add additional circuits easily as needed.

REDUNDANCY REQUIREMENTS

Providing redundancy and/or fault tolerance in the power system can increase the availability of a computing system. In high availability environments, a common way to provide redundancy is to supply two independent power paths to each piece of computing equipment; the equipment in turn accepts the two power feeds via independent paralleled power supplies that are sized such that the equipment will continue to operate with only one power path. This system provides the following key advantages:

- If a power supply fails the system continues to operate
- If one power feed fails due to equipment malfunction the system continues to operate
- If one power feed fails due to user error the system continues to operate
- If the power supply fails in a way which faults the power feed and trips breakers, the equipment sharing the breaker is not affected.

• If one power feed needs to be shut down for maintenance or upgrade, the system continues to operate.

For this approach to be effective, the following requirements must be met:

1. The protected equipment must support dual power feeds and

operate with one feed faulted

2. The loading of breakers within each power path must always be less than 50% of trip rating during normal conditions, so that the increase in load that will accompany failure of the alternate path does not cause breakers to trip. This also helps prevent tripping of the alternate path due to low line voltage conditions.

Meeting these two requirements can be very difficult. Some computing equipment is only available with a single power cord. There is also equipment manufactured with three power cords, where any two are needed for proper operation. These types of equipment cannot operate with the loss of one power feed. In these cases, an Automatic Transfer Switch (ATS) can be used which generates a single feed from two inputs. Such an ATS may be deployed centrally or it may be deployed in a distributed manner by placing small rack mount ATS in the rack enclosure with the protected equipment.

An adaptable rack enclosure power system would be able

Voltage	Max branch current rating	Maximum kW Capacity per branch	Total rack power for 1/2/3/4 branch circuits
120V	20A	2.4 kW	2.4 / 4.8 / 7.2 / 9.6
208V	20A	4.2 kW	4.2 / 8.3 / 12.5 / 16.6

Table 1 – Branch circuit power limitations

will need to be greater than one to support the power density of current and future IT technology.

Combining the data from Table 1 and data from Figure 2, the following conclusions can be drawn:

- A single 120V branch circuit can supply the load requirement for the most common rack enclosures today, but this will not be true in the future.
- Two 120V branch circuits, or one 208V branch circuit, can supply the load requirement for approximately 80% of rack enclosures today, but only 40% of racks in the future.
- Three 120V branch circuits in North America can supply the load requirement for over 92% of rack enclosures today, and still over 85% in the future.

Note that the inability to provide sufficient branch circuits to a rack enclosure does not prevent operation of the system. If the rack has insufficient power distribution capacity, the power drawn by a rack enclosure can be reduced by removing

FOOTNOTE

1 Note that 30A circuits are also sent to the rack but these circuits are feeder circuits and not branch circuits, because they require additional circuit breakers in the rack as described in later sections. Very few rack devices can directly utilize a 30A branch circuit; these are usually blades, routers or free-standing servers or storage devices.

to support a single or dual path environment or a hybrid of both single and dual equipment. In addition, it is necessary to provide current monitoring to ensure that all circuits are loaded below 50% capacity in order to prevent breaker tripping during a loss of one power path.

OVERLOAD PROTECTION REQUIREMENTS

One of the most misunderstood concepts of power distribution is the over-current protection of branch circuits. Each branch circuit in a rack enclosure must be supplied by an independent circuit breaker and a typical rack enclosure will need multiple branch circuits. Figure 3 illustrates the common methods of power distribution to the rack, showing different branch circuit configurations. In Figure 3a, a single branch circuit supplies a rack. For a 20 Amp system, this arrangement is limited to 2.4 kW max capacity for 120V or 4.2 kW max capacity for 208V. To achieve higher rack power, multiple branch circuits are required. There are two options for providing multiple branch circuits to a rack enclosure, and these are shown in Figure 3b and 3c.

The arrangements of Figure 3b and 3c are capable of providing the same power, but with a different wiring and circuit breaker arrangement. Note that in Figure 3b the conduit or “whip” contains multiple branch circuits. These alternatives give rise to significant advantages and disadvantages as summarized in Table 2.

The summary of Table 2 suggests there is a significant advantage to avoiding the need to generate branch circuits in the rack enclosure.

Most users who send 30A or larger circuits to racks do not understand that these circuits are feeder circuits and not branch circuits. When 30A whips are used, the typical 20A branch circuits required to supply receptacles must be provided by branch-rated breakers located within the racks.

An adaptable rack power system would eliminate the need for hard wiring, cascaded breakers, and breaker coordination analysis, which would suggest a preferred approach of multiple branch circuits per rack.

Ideally, multiple branches would be provided using a single multi-conductor cable to the rack in order to simplify wiring to the rack.

CONNECTOR REQUIREMENTS

Over 99.99% of all AC powered equipment used in rack enclosures are connected via a power cord and plug (a negligible fraction is hard-wired). While most have plugs, these plug types can vary greatly from one product to another.

In North America, the approximate statistical breakdown of frequency of occurrence for plug types is provided in Table 3.

In the rest of the world, plugs vary by country, which makes this situation more complex. However, unlike North America, most countries use a single service voltage and therefore power cords are rated for 230V 16A. This means that a single plug type serves most applications from small hubs to enterprise servers.

Therefore, outside of North America, a single country-specific plug type handles 99% of applications.

It is important to note that 99% of all IT equipment in the data center utilizes a detachable power cord. This means that the plug type can be changed. OEM suppliers take advantage of this when creating complete rack systems and often will install cords with IEC 60320 (previously IEC-320) style power plugs on all the equipment in the rack enclosure, along with an IEC60320 style outlet strip. This has the benefit that a single configuration can be used worldwide.

The number of receptacles required in a rack enclosure varies dramatically with the installed equipment. A rack enclosure may contain only a single load as a minimum. Conversely it may be populated with (42) thin servers with dual power cords for a total requirement of 84 receptacles.

An adaptable rack enclosure power system would be able to provide power receptacles for all the various plug types, which might be encountered, as well as two feeds, each containing (42). To accomplish this, one must provide a large quantity and assortment of receptacles in every rack enclosure, or provide a number of easily changeable outlet strip options to meet evolving requirements.

HARMONIC REQUIREMENTS

Historically, computing equipment generated harmonic currents on AC power lines, which led to the need to incorporate specialized features into power systems such as oversized neutral wiring and K-rated transformers. During the 1990s, regulations placed on the design of computing equipment,

Figure 3 – Illustration of methods of delivering branch circuits to the rack, showing alternate ways of supplying multiple branch circuits to a rack

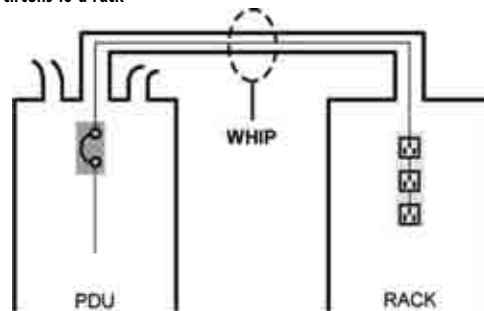


Figure 3a – Single branch circuit to the rack

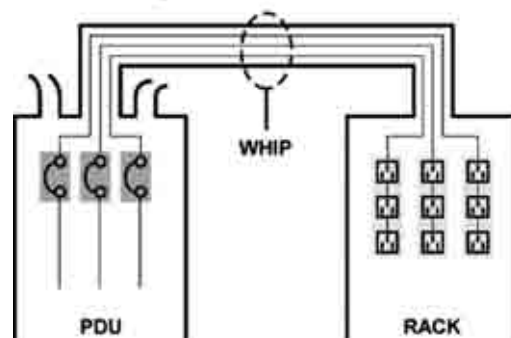


Figure 3b – Multiple branches: Generate required branch circuits at the PDU

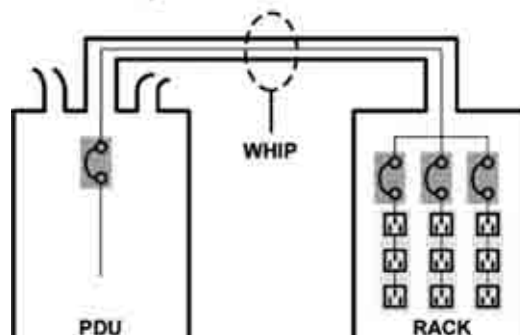


Figure 3c – Multiple branches: Generate required branch circuits within the rack

combined with the gradual retirement of older equipment, resulted in the elimination of this as a problem by the year 2000.

Today, lighting and power distribution transformers are the predominant source of harmonic currents in data centers. Harmonic-rated wiring and transformers are not needed in the rack enclosure power environment.

DE-RATING REQUIREMENTS

Operating with circuits at the rated current limit is not desirable, since the circuit breakers are on the edge of the trip rating and may trip. Therefore, the user should not expect to utilize the full current or power rating of the system, but should apply a de-rating factor. The National Electric Code specifies a 20% de-rating factor be applied to rack mounted PDUs. This is a practical and recommended de-rating factor. However, some users conservatively specify lower de-rating factors, such as 30% or even 40%. The power capacities of the distribution architectures described in this paper are full rated values unless otherwise stated, and therefore the actual values should be computed by applying the desired de-rating factor.

CABLING REQUIREMENTS

Cables to deliver power to the rack enclosures are an essential part of the rack enclosure power system. A common practice today is to use under floor power cabling. The under floor power cabling method presents a number of barriers to adaptability.

In an adaptable rack enclosure power system, the cabling provided to each rack would provide all the branch circuits and voltages that might ever be required. No changes to the cabling would be required due to equipment changes in the rack enclosure. It would also be easy and safe to provide the appropriate power feeds to additional rack enclosures in the future.

CURRENT MONITORING REQUIREMENTS

Rack enclosure power systems are subject to constant load changes due to the installation and removal of equipment and to the dynamic power draw variation in the installed equipment. These circumstances lead to a requirement to monitor power flowing in branch circuits in order to prevent failures or hazard due to overloads.

CONSISTENCY REQUIREMENT

Due to the large number of power circuits in the typical data center, there is a significant advantage to minimizing the

	Number of feeds	Location of breakers	Advantages	Disadvantages
Generate required branch circuits at the PDU	One feed per required branch circuit	PDU only	Fewer total breakers No fault coordination issues Each branch usable to full capacity Feed to rack may be pluggable	More circuit breaker positions required in the PDU
Generate required branch circuits within the rack enclosure	Fewer feeds per voltage required within the rack enclosure	Feed breakers in PDU Branch breakers located within rack enclosure	Fewer feeds to rack Fewer breakers in the PDU	More breakers to monitor for overload. Fault coordination. Branches may not be usable to full capacity. More breakers in series reduces reliability Feed may need to be hardwired.

Table 2 – Comparison of the two options for providing multiple branch circuits to a rack enclosure

Frequency	Plug Type	Description	Where used
80%	NEMA 5-15P	120V 15A	Small servers, hubs, departmental switches, monitors, power blocks
13%	IEC 60320 (previously IEC-320) C-13	120 or 208V 15A	Enterprise servers
3%	NEMA L6-20P	208V 20A Locking	Enterprise servers, routers
2%	IEC-60320 C-19	120 or 208V 20A	Some blade servers
1%	NEMA 5-20P	120V 20A	Large departmental servers
0.9%	NEMA L6-30P	208V 30A Locking	Enterprise servers, routers
0.1%	NEMA 6-15P	208V 15A	Large departmental servers
0.01%	NEMA 15-30P	208V 30A 3-phase	Some blade servers

Table 3 – Frequency of occurrence of different plug types on IT equipment in North America

different types of power distribution provided (branch circuit ratings, poles per whip, circuit breaker types and location, etc). Ideally, a uniform single type of power feed would be provided to every rack to maximize flexibility and reduce human error.

Human error is a constant threat in a data center and has been the cause of much downtime. Standardizing on a common power distribution circuit that fulfills the need 97% of the time is just one method of reducing the risk of human error. With standardized whips users are less apt to become confused, parts are minimized and learning curves are accelerated all which lower the risk of a costly mistake.

SELECTING THE APPROPRIATE POWER DISTRIBUTION SYSTEM

Despite the number of requirements, there are still many different combinations of circuits that can be used to power rack enclosures, each providing different total power capacity and differing in key features. There are at least 25 practical but different ways to provide power to rack enclosures in the range of

Figure 4 – Illustration of the four preferred forms of power distribution to the rack

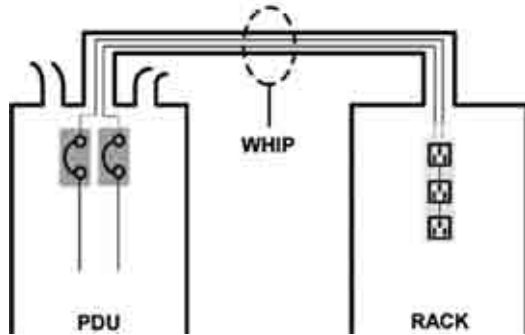


Figure 4a – 208V 20A whip

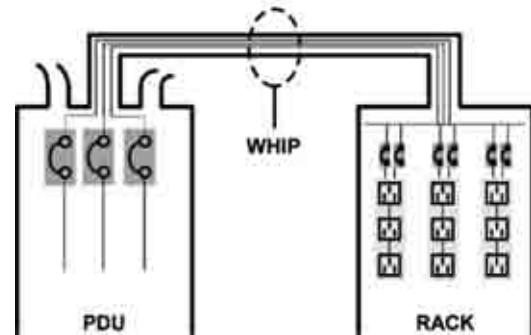


Figure 4c – 208V 50A 3-phase whip

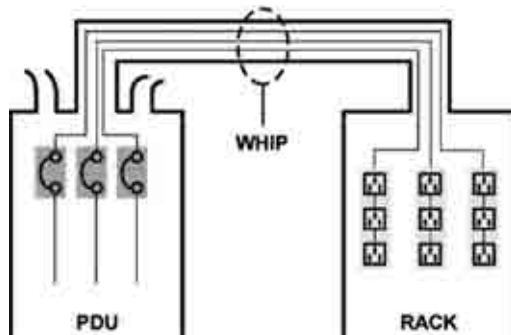


Figure 4b – 208V 20A 3-phase whip

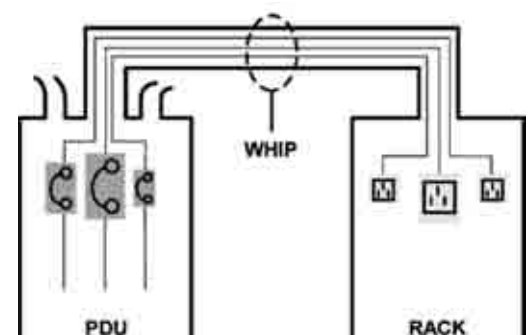


Figure 4d – Dedicated whips

2.4 kW to 36 kW per rack. The details of these alternatives are provided in Appendix A.

Through a systematic investigation of these alternatives, it is possible to determine that these alternatives are not equivalent in their costs and benefits, and that some options are clearly preferred. The analysis of Appendix A, when considered with the requirements defined in the previous section, suggests that there are four essential preferred forms of rack power distribution between the PDUs and the racks, which are used in multiples per rack to achieve a desired power density. The four preferred forms are:

- 208V 20A whips
- 120/208V 20A 3-phase whips
- 208V 50A 3-phase whips
- Dedicated whips

Figure 4 illustrates these four preferred forms by showing the branch circuit configurations. The characteristics and advantages of these four essential preferred

types of power distribution are provided in Table 4. In Table 4, the shaded attributes represent the best performance for that characteristic. The figure shows the clear advantage of 3-phase distribution to the rack.

The analysis of this paper suggests that distribution whips that include single or 3-phase 30A whips are not pre-

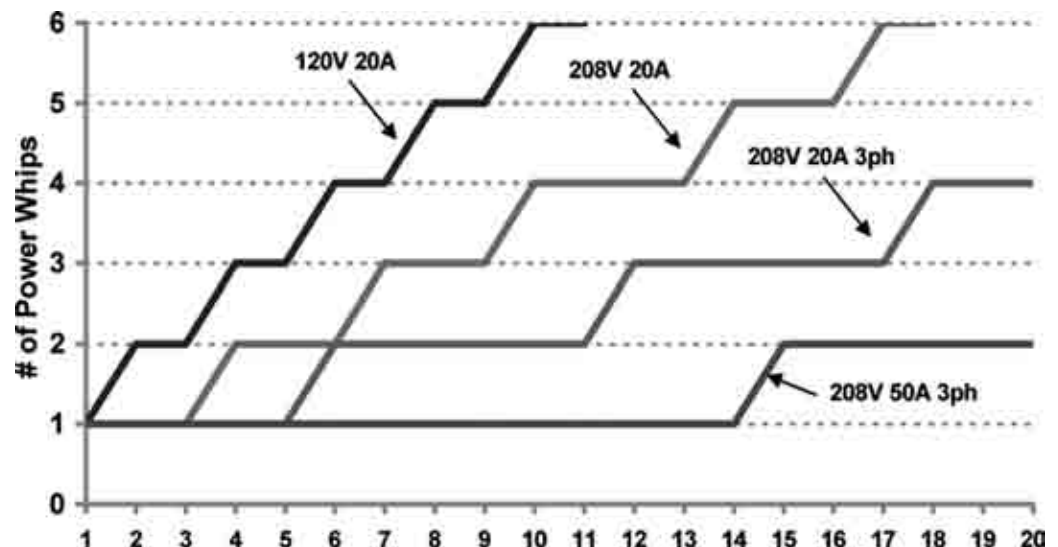


Figure 5 – Number of rack power whips or feeds required as a function of the rack power rating for four different whip ratings
Note: this chart assumes whip derating to 80% of rated capacity

ferred except in the case of dedicated whips. The 30A whip value is not optimal because the most common branch circuit size that must be generated in a rack is 20A, which leads to two undesirable problems with a 30A whip size:

1) The coordination between a 20A branch circuit breaker and a 30A feeder breaker is difficult to achieve increasing the likelihood of cascade breaker tripping.

2) Two 20A branches are required to fully utilize a single 30A whip phase feed, and if one of these branches is fully utilized the other can only be halfway utilized. This is an inefficient use of circuit breakers; furthermore, the feeder breaker may trip before the branch breakers trip.

When a density higher than that provided by one or more 20A or 20A 3-phase whips is required, a 50A 3-phase whip is the preferred solution over a 30A 3-phase whip.

The preferred forms may be used in multiples to achieve higher total rack power ratings. Figure 5 shows the number of whips required to achieve increasing total rack power ratings. The four curves on the chart represent the whip count for various types of power distribution. The 120V 20A rack power distribution circuit is not a preferred approach but is in the chart for reference. Note that the number of whips required increased linearly with rack power rating as expected. For power ratings greater than 11 kW per rack the number of whips becomes very large for all systems except the 208V 50A 3ph system.

Note that for 2N dual power path systems the number of whips in Figure 5 must be multiplied by 2.

DEDICATED WHIPS

One of the preferred forms of power distribution is dedicated whips. However, dedicated whips are preferred only when the load equipment in a rack has a small number of power cords that each draw a large amount of power, particularly if the equipment uses an unusual plug type or power configuration. Certain blade servers and SAN storage units meet these criteria, for example, a large blade server power subsystem that has a 3-phase NEMA L15-30 power plug. The advantage of dedicated whips is that they never require an additional circuit breaker in the rack, increasing reliability and saving expense. The big disadvantage of dedicated whips is the lack of flexibility when equipment is changed in the future. Dedicated whips are compared to standard 208V 50A whips in Table 5.

In general, dedicated whips should only be used when the power requirement or plug configuration cannot be provided by a standard 208V 50A 3-phase circuit, or when cost is much more important than the ability to reconfigure the rack later.

Table 4 – Characteristics of the four preferred types of rack power distribution

Characteristic	208V 20A	120/208V 20A 3-phase	208V 50A 3-phase	Dedicated 208V	Comment
kW levels obtainable from 1, 2, 3 or 4 whips	4.2 8.3 12.5 16.6	7.2 14.4 21.6 28.8	18 36 54 72	4.2; 6.2 8.3; 12.5 12.5; 18.7 16.6; 25	Dedicated whips assume 20A or 30A single phase whips. Note that 3-phase dedicated whips are also possible but extremely rare.
kW per whip	4.2	7.2	18	6.2	
kW per PDU breaker panel pole position	2.1	2.4	6.0	3.1	
Max single load kW	4.2	4.2	10.4	6.2	There are currently almost no production IT rack products that require over 4.2kW per plug, but this could change.
# of 1kW IT devices per whip	4	6	18	1	Note that a dedicated feed only supports a single device.
# of breakers in series with load	1	1	2	1	
120V support	N	Y	N	N	The ability to handle 120V circuits is an advantage since most equipment comes with a 120V power cord.
Fault coordination	E	E	G	E	Placing additional branch breakers in the racks, as required for the 30A designs, compromises fault coordination.
Cost per kW @ 2kW per rack	\$350	\$310	\$475	variable	Includes source breaker, whip, and rack PDU. Note that a dedicated whip is required for each IT device.
Cost per kW @ 10kW per rack	\$275	\$124	\$95	variable	Includes source breaker, whip, and rack PDU.

Note: Shading indicates best performance for the characteristic

Note: whip costs do not include any installation costs

Fault coordination - legend: E = excellent G = good P = poor

DISTRIBUTION SELECTION STRATEGY

From this analysis it is possible to draw conclusions regarding a preferred arrangement for branch circuits, which is as follows:

1) Use a single 120/208V 20A 3-phase power whip to supply common medium-density racks up to approximately 6 kW/rack; supply this by default to every rack.

2) Use two 120/208V 20A 3-phase whips to supply higher density racks up to approximately 12 kW per rack.

3) For densely packed 1U server or blade server applications, use either one or two 208V 50A 3-phase whips.

4) For certain extremely high density loads that have input current requirements per power cord of over 20A, run separate dedicated 20A or 30A single or three phase whips per device, depending on the device plug type (consult APC application notes for specific recommendations for specific brands and models of blade servers)

	Number of whips	Method of change	Advantages	Disadvantages
Standard 208V 50A 3-phase whips	One whip per every 18kW	Easy: Plug in different breaker / outlet strips in the rack	Fewer breakers in the PDU Various outlets provided for small or unplanned equipment	Some breakers located in the rack
Dedicated whips	One whip per power cord in the rack	Difficult: Power down and run new wires to the PDU	No fault coordination issues Fewer total breakers Can handle any strange plug or circuit size Lowest cost	Must plan in advance and know every power cord that might exist in the rack No provision for small ancillary IT equipment Feed needs to be hardwired.

Table 5 – Comparison of the two options for providing very high density power

ADAPTABLE POWER ARCHITECTURE FOR RACK ENCLOSURES

The growing recognition of the issues described in this paper have led data center and network room designers and operators to develop their own ingenious solutions to address the need for adaptable rack enclosure power systems. Nevertheless, an integrated and cost-effective approach from the point of view of the equipment providers has been lacking. A fully integrated approach would include a modular system that implements all aspects of power distribution from the AC mains connection of the facility, through the UPS, through the power panels, all the way down to the mechanics of connection of the plugs in the rack enclosures.

The first integrated and adaptable rack enclosure power system was introduced in 2001 and is shown in Figure 6. The patent-pending InfraStruXure system includes components that are engineered to meet the requirements of an adaptable rack enclosure power system. The system includes prefabricated multibranch power distribution whips, Quick-change multi-voltage metered outlet strips with various receptacle configurations, pre-engineered circuit breaker coordination, single and dual-path power feed support configurable at the rack enclosure or row level, point of use DC capability, and rapid conduit-free installation.

This system is provided as an integrated system that can be configured to order from stock components.

In addition to the capability of the adaptable rack enclosure power system to respond quickly and economically to change, there are cycle time and cost advantages associated with the initial installation of the system, including a dramatic simplification to the up-front engineering and

installation work associated with data center design. Furthermore, the ability to adapt the rack enclosure power system can allow the system to be “right sized” to the actual load requirement and grow with expanding needs. The economic benefits of rightsizing can be well over 50% of the lifecycle cost of a data center or network room.

CONCLUSIONS

Individual rack enclosure power consumption in the data center or network room varies widely and is expected to grow in the next few years. Rack enclosure equipment is replaced 5 or more times during the life of a data center in a piecemeal manner.

This situation requires a rack enclosure power distribution system that can cope with the changing requirements. Key requirements of an effective rack power distribution system were described, which suggest a practical rack enclosure power architecture that can meet the requirements for an adaptable rack enclosure power system. The recommended approach standardizes on four key ways to distribute power, along with a strategy for selection of the best approach for a given installation. When this approach is implemented, the result is a power distribution system which reduces human error, adapts to changing requirements, minimizes the need for advance planning and meets the requirements of high density IT equipment.

Neil Rasmussen is a founder and the Chief Technical Officer of American Power Conversion. At APC, Neil directs the world's largest R&D budget devoted to Power, Cooling, and Rack infrastructure for critical networks, with principal product development centers in Massachusetts, Missouri, Denmark, Rhode Island, Taiwan, and Ireland.



Figure 6 – An example of an adaptable rack power system

APPENDIX A: DETAILED ANALYSIS OF AN EXHAUSTIVE SET OF RACK POWER DELIVERY OPTIONS

Various practical circuit types, including multiples, which can provide rack power, are listed in Table A1. The table is ranked by increasing rack power capacity.

Table A1 – Characteristics of practical rack power circuit configurations

total kw	circuit type	# whips	kw / whip	# poles	kw / pole	max single load kW	# breakers	120V support	208V support	coordination
2.4	120V 20A	1	2.4	1	2.4	2.4	1	Y		E
3.6	120V 30A	1	3.6	1	3.6	2.4	3	Y		P
4.2	208 20A	1	4.2	2	2.1	4.2	2		Y	E
4.8	120V 20A	2	2.4	2	2.4	2.4	2	Y		E
6.2	208 30A	1	6.2	2	3.1	6.2	6		Y	P
7.2	120V 20A	3	2.4	3	2.4	2.4	3	Y		E
7.2	120V 30A	2	3.6	2	3.6	2.4	6	Y		P
7.2	120/208 20A 3 ph	1	7.2	3	2.4	4.2	3	Y	Y	E
8.4	208 20A	2	4.2	4	2.1	4.2	4		Y	E
10.8	120/208 30A 3 ph	1	10.8	3	3.6	6.2	9	Y	Y	P
10.8	208 30A 3 ph	1	10.8	3	3.6	6.2	9		Y	P
12.6	208 20A	3	4.2	6	2.1	4.2	6		Y	E
12.4	208 30A	2	6.2	4	3.1	6.2	12		Y	P
14.4	120/208 20A 3 ph	2	7.2	6	2.4	4.2	6	Y	Y	E
16.8	208 20A	4	4.2	8	2.1	4.2	8		Y	E
18.0	208 50A 3 ph	1	18	3	6.0	10.4	9		Y	G
18.6	208 30A	3	6.2	6	3.1	6.2	18		Y	P
21.0	208 20A	5	4.2	10	2.1	4.2	10		Y	E
21.6	120/208 30A 3 ph	2	10.8	6	3.6	6.2	18	Y	Y	P
21.6	120/208 20A 3 ph	3	7.2	9	2.4	4.2	9	Y	Y	E
21.6	208 60A 3 ph	1	21.6	3	7.2	12.5	12		Y	G
25.2	208 20A	6	4.2	12	2.1	4.2	12	Y	Y	E
24.8	208 30A	4	6.2	8	3.1	6.2	24		Y	E
28.8	120/208 20A 3 ph	4	7.2	12	2.4	4.2	12	Y	Y	E
36.0	208 50A 3 ph	2	18	6	6.0	10.4	18		Y	G

Fault coordination – legend: E = excellent G = good P = poor

The options described in Table A1 are limited to a practical maximum of 6 whips, and includes only multiples where all of the whips are of the same circuit configuration. Dedicated whips may be some mixed combination of the whips in the above list per rack.

While this list is exhaustive, certain combinations can be eliminated if the objective is to provide power to high-density rack enclosures. Power systems for high-density rack enclosures must provide 208V capability since there are many high-density IT loads that do not accept 120V.

Furthermore, a power system for high-density loads

should also be able to power single loads of at least 3kW since there are many high-density loads that require up to 3kW. In addition, a power system for high-density loads should not exhibit a poor breaker coordination ratio. By excluding options that do not meet these criteria, the list of Table A1 is reduced to the list of Table A2.

Table A2 – Characteristics of rack power circuit configurations suitable for high density loads

total kw	circuit type	# whips	kw / whip	# poles	kw / pole	max single load kW	# breakers	120V support	208V support	coordination
7.2	120/208 20A 3 ph	1	7.2	3	2.4	4.2	3	Y	Y	E
8.4	208 20A	2	4.2	4	2.1	4.2	4		Y	E
12.6	208 20A	3	4.2	6	2.1	4.2	6		Y	E
14.4	120/208 20A 3 ph	2	7.2	6	2.4	4.2	6	Y	Y	E
16.8	208 20A	4	4.2	8	2.1	4.2	8		Y	E
18.0	208 50A 3 ph	1	18	3	6.0	10.4	9		Y	G
21.0	208 20A	5	4.2	10	2.1	4.2	10		Y	E
21.6	120/208 20A 3 ph	3	7.2	9	2.4	4.2	9	Y	Y	E
21.6	208 60A 3 ph	1	21.6	3	7.2	12.5	12		Y	G
25.2	208 20A	6	4.2	12	2.1	4.2	12	Y	Y	E
28.8	120/208 20A 3 ph	4	7.2	12	2.4	4.2	12	Y	Y	E
36.0	208 50A 3 ph	2	18	6	6.0	10.4	18		Y	G

Fault coordination – legend: E = excellent G = good P = poor

PRIMARY-SIDE TRANSFORMER PROTECTION

By Peter J. Meyer, S&C Electric Company

INTRODUCTION

There are many different protection schemes used today for distribution substation transformers, covering a wide range of expense and complexity — from high-end ring bus and breaker-and-one-half schemes, to low-end flash bus and grounding switch schemes. Given the pressure to increase the continuity of service, more advanced protective devices are called for than a motor-operated disconnect switch to initiate a fault. Today, the best practice is to individually protect each transformer with a local protective device.

Doing so eliminates the need to take off-line all transformers connected to the transmission line, when only one transformer has experienced a fault... unnecessary interruptions to service are avoided.

Secondary-side bus faults are the most common type of event that a primary-side protective device must interrupt.

But they may be difficult for some devices due to the high frequency transient recovery voltage (TRV). One might think that a device with a robust fault interrupting rating — such as a 40-kA circuit breaker — would be able to handle a relatively low-magnitude fault on the secondary-side of the transformer. But the secondary-fault interrupting rating of a device is dependent on the device's ability to withstand a fast-rise transient voltage — much faster than that seen during high-current fault interrupting. Therefore, the device must be specifically tested to determine its ability to withstand and interrupt fast TRVs. A device with a 40-kA primary-fault interrupting rating may not necessarily be able to interrupt 4-kA secondary faults with a fast-rise transient voltage.

Standards for testing a device for appropriate secondary-side fault interrupting capabilities — which take into account high-frequency TRVs — are currently being reviewed. The draft standard, PC37.016, “Standard for AC High Voltage Circuit Switchers rated 15kV through 245kV”, [1] provides the testing requirements to verify that a protective device can interrupt a fast TRV. C37.06.1-1997, “Trial Use Guide for High-Voltage Circuit-Breakers Rated on a Symmetrical Current Basis Designated Definite Purpose for Fast Transient Recovery Voltage Rise Times”, [2] does so as well, although the main C37.06 standard, “AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis”, [3] does not currently incorporate requirements for testing a breaker's ability to interrupt faults with associated fast-rise TRV, or to require a secondary-side fault interrupting rating.

Manufacturers of purpose-built equipment for transformer protection, including the author's company, have traditionally tested for fast-transient TRVs and provide their equipment with a secondary-side fault interrupting rating.

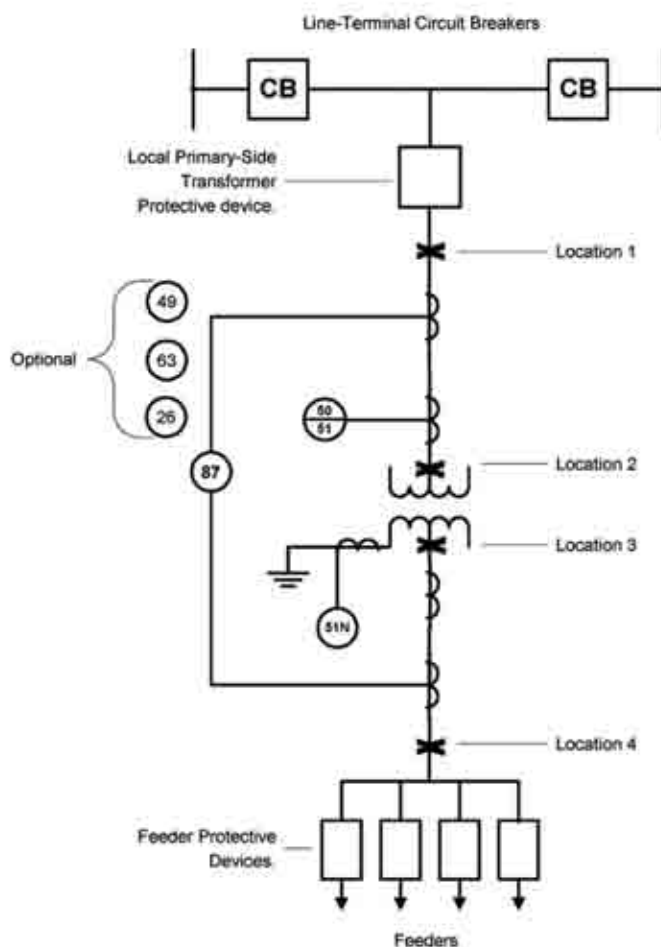
Given the position of the primary-side device and that most fault activity is on the secondary bus, this secondary-side interrupting rating is critical for a primary-side protective

device. Before discussing how to select a primary-side protective device, let's examine the possible locations of faults and the subsequent response of the protective equipment.

LOCATIONS OF FAULTS AFFECTING THE TRANSFORMER

Primary-side protective devices are widely applied at load tap transformers where the available primary fault current exceeds the device's primary-fault interrupting rating.

Overlapping protection from statistically rare high-current primary faults is afforded by the line-terminal circuit breakers and first-zone phase- and ground-fault line-protective relays. On systems using line-terminal circuit breakers, circuit interruption following a high-current primary fault is typically accomplished by the line breakers in 3 cycles. A local primary-side



Typical Transformer Protective Scheme Using Relayed Device.
FIGURE 1

transformer protective device will respond to faults internal to the transformer and to faults on the secondary bus that is included in its zone of protection. It can also provide back-up protection for the secondary-side protective device(s). A properly applied transformer protective system will overlap some of the protection provided by the line-terminal circuit breakers and supplement the protection afforded by the secondary-side protective device(s).

To understand how a primary-side transformer protective device is applied, let's look at Figure 1. It shows a one-line diagram of the relay protection scheme used for a typical radially tapped transformer protective scheme — including four locations where faults may occur.

LOCATION 1: FAULTS ON BUS BETWEEN TRANSFORMER PROTECTIVE DEVICE AND TRANSFORMER, AND TRANSFORMER PRIMARY BUSHING-TO-GROUND FAULTS

The short length of bus and greater line-to-ground clearance make these types of faults rare. Fault current magnitudes in this area can be high because they are only limited by the upstream impedance of the system. This location is typically not part of the relaying for a primary side protective device due to the location of the primary side current transformers. It is important to remember that the current transformers for the transformer differential protection are typically located on the bushings of the transformer. Therefore, the primary-side protective device will not receive a trip signal for events on the primary bus, and this device will not get called on to clear full primary-side fault currents on the primary side. For example, primary arrester failures will be cleared by the line terminal breakers, as shown in Figure 1.

Faults in this area cannot usually be detected by the relay schemes used with a local device. If current transformers are available at the primary-side protective device, a relay scheme could be used to cover this small section of the high-side bus but, due to the 3-cycle speed of operation of line-terminal circuit breakers, both devices would respond to the event unless an expensive pilot-wire blocking scheme is implemented. On more complex substation bus arrangements like ring-bus or breaker-and-one-half schemes, the primary-side protective device usually has current transformers and is used to clear faults in this short section.

LOCATION 2: TRANSFORMER PRIMARY WINDING FAULTS

Faults at the transformer primary winding are uncommon in a well-protected and well-maintained transformer. The fault current magnitude can be either high or low, depending on the location of the fault within the winding.

Typical winding faults are turn-to-turn or multiple-turn and are low magnitude, on the order of load current. Less likely winding-to-ground faults are limited by the winding impedance to low to moderate magnitude. A winding-to-ground fault near the high-voltage bushing results in high currents limited by the system impedance. These faults are detected by differential, overcurrent, or ground fault relaying, or by sudden pressure, gas analysis, or other overpressure detection methods. Depending on where they occur and the magnitude of the fault current, they will either be cleared by the line breakers or the primary side protective device.

LOCATION 3: TRANSFORMER SECONDARY WINDING FAULTS

Secondary winding faults are also uncommon in a well-protected and well-maintained transformer. The fault current

magnitude can be either low or moderate depending on the location of the fault within the winding.

Turn-to-turn and multiple-turn faults are typically low magnitude, limited by the winding impedance. Winding-to-ground faults are of moderate magnitude and always less than the available secondary fault current limited by the transformer impedance. These faults are detected by differential, overcurrent, or ground-fault relaying, or by sudden pressure, gas analysis, or other overpressure detection methods, and are cleared by the primary-side transformer protective device without disturbing the transmission line.

LOCATION 4: TRANSFORMER SECONDARY BUS FAULTS AND SECONDARY BUSHING-TO-GROUND FAULTS

Secondary bus and transformer secondary bushing-to-ground faults represent the majority of faults that a transformer protective device will have to interrupt. With its typically greater length and smaller phase-to-ground distance, it's more likely that wildlife intrusion or nearby equipment problems will cause a fault on the secondary bus. The fault current magnitude is moderate because it is limited by the transformer impedance. Faults in this location are detected by secondary differential or overcurrent protective schemes, and are cleared by the primary-side transformer protective device without disturbing the transmission line.

SECONDARY-SIDE FAULT INTERRUPTION

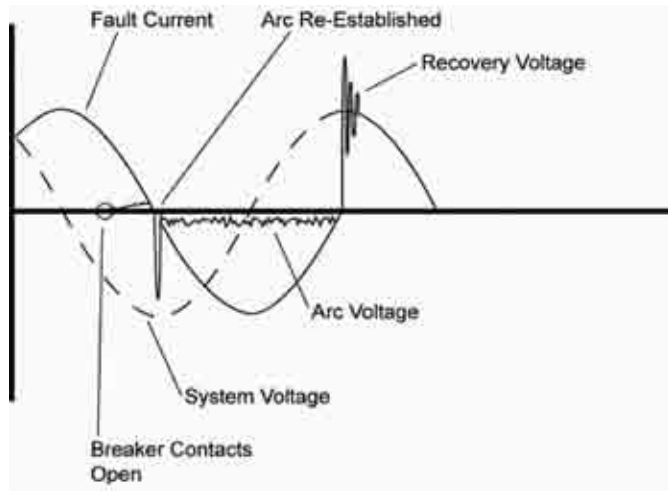
Secondary-side faults, found in Location 4 in Figure 1, are difficult to interrupt. Special attention must be paid to selecting a device that can interrupt these low current transformer-limited faults. Such faults are limited by the impedance of the transformer, so they have modest magnitudes, but the transient recovery voltage (TRV) frequency seen by the interrupting device after clearing the current is high because of the small bushing and winding capacitance of the transformer, compared to its large inductance.

$$F = \frac{1}{2\pi\sqrt{LC}}$$

To illustrate, a fault in Location 4 would be detected by the transformer's differential relaying, which would signal the primary-side device to open. (See Figure 1.) In a puffer-type SF6 circuit-switcher or circuit breaker, during the opening operation, the SF6 gas is compressed by moving the cylinder supporting the contact system, or by a piston which forces the SF6 through the interrupting nozzle.

This causes a rapid gas flow across the arc, which serves to cool the arc while the arc is lengthened as the contacts move farther apart. By controlling and cooling the arc, its conductivity can be rapidly decreased as the current passes through zero, such that the arc is extinguished and the circuit is interrupted. At that time, the transient recovery voltage across the gap between the contacts is impinged, as a race starts between the cooling processes within the transformer protective device due to increasing dielectric strength and rising recovery voltage across the contacts. If the cooling processes are successful, the interruption is successful and there is no resumption in current. When interrupting a secondary-side fault across a transformer, the reactance-to-resistance ratio (X/R) is high, so fault current will significantly lag the voltage. See Figure 2.

When current is at zero, the voltage is at or near peak. In



Contact Arc-Interruption and Recovery Voltage
FIGURE 2

general, the impedance of the transformer is high compared to the source, so there is a significant voltage (assumed to be .9 per unit by C37.016) [3] trapped in the stray capacitance of the transformer. As this energy resonates back and forth between the electric field of the stray capacitance and the magnetic field of the transformer inductance, a substantial voltage excursion occurs on the terminals of the transformer protective device, which highly stresses the contact gap due to the high-frequency nature of this excursion — typically on the order of 10 kHz to 15 kHz. If the insulation between the contacts recovers more quickly than the TRV, the interruption is successful. If the TRV creates too excessive a rise in voltage, re-ignition of the arc can occur.

Many primary-side devices are assigned a secondary-fault interrupting rating and tested to ensure that they are capable of interrupting transformer-limited faults. In some cases,

multi-purpose devices with high primary-fault interrupting ratings may not be able to interrupt fast TRVs — testing with a fast TRV needs to be specified to ensure the device can handle this duty. See Figure 3.

Secondary fault currents are typically in the range of 2 kA to 6 kA. To determine the fault current seen by the primary-side protective device for a fault on the secondary side, an infinite (zero-impedance) source is assumed. The value can be calculated using the following equation:

$$I = \frac{57.8P}{(\%Z)E}$$

where

I = Inherent secondary-fault current, amperes

P = Transformer self-cooled three-phase rating, kVA

E = Primary-Side System phase-to-phase voltage, kV

%Z = Percent transformer primary-to-secondary impedance, referred to transformer self-cooled three-phase kVA rating

For example, a 37.5/50/62.5 MVA transformer at 115 kV with 8% impedance will provide an inherent secondary-fault current of 2,356 amperes, calculated as follows:

$$I = \frac{57.8 * 37,500 \text{ kVA}}{8 * 115 \text{ kV}} = 2,356 \text{ A}$$

Therefore, the maximum current on the high side of the transformer resulting from a fault on the secondary side bus will be 2,356 amperes with a high-frequency TRV. The primary-side protective device should be rated to clear this type of secondary fault. [4]

SELECTING TRANSFORMER PRIMARY-SIDE PROTECTIVE DEVICES

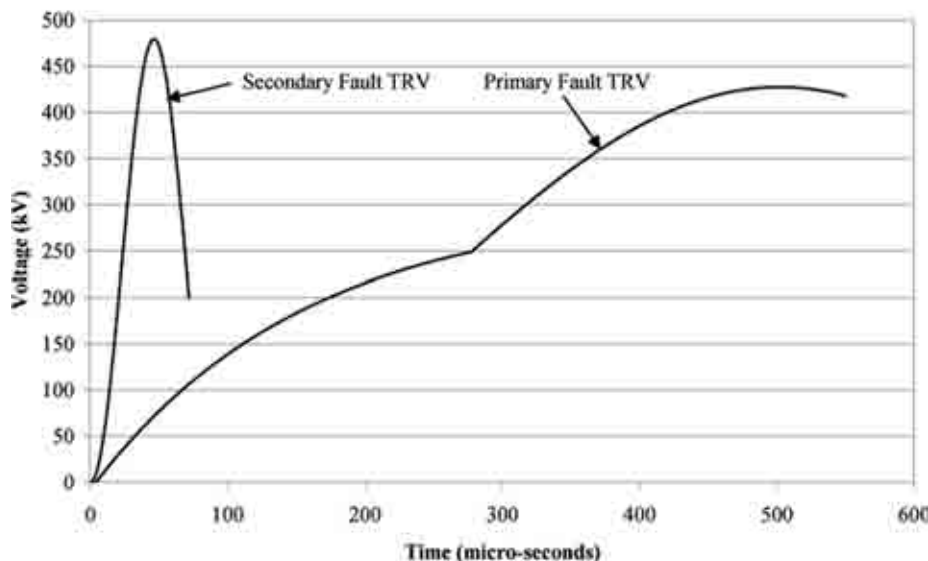
Selecting a primary-side device for a new substation can be just as much an economic decision as a technical one.

Smaller, less expensive transformers are often protected with power fuses. In the past, these transformers have been protected with remote protection schemes which rely on the line-terminal breakers to protect the transformer, as well as to provide back-up protection for the secondary-side protective device. Larger transformers and transformers serving critical loads are usually protected with devices that use relaying schemes — from simple overcurrent relays to sophisticated combinations of differential, sudden pressure, overcurrent and instantaneous relays that fully coordinate with upstream and downstream devices.

Once a device with the appropriate secondary-side interrupting rating requirements has been identified, the selection process largely becomes a matter of choosing the features and configuration appropriate to the installation.

Factors such as available substation real estate, bus layout, seismic

TRV Comparison for a 230 kV Device



TRV Comparison for a 230 kV Device
FIGURE 3

requirements, structure height requirements, equipment maintenance cycles, and system ratings are only a few of the factors that must be considered... the suitability of the device for a particular substation is usually a matter of utility preference.

In some cases, a device is selected to upgrade a power fuse installation. In such instances, primary-side current transformers, substation batteries, and control power are usually not present in the substation, and the cost of installing this infrastructure is often weighed against the benefits of more-sophisticated relayed transformer protection.

In other cases, a relayed device (like a circuit-switcher or circuit breaker) is selected to upgrade a remote protection scheme. Although widely used in the past, such schemes are slowly being phased out. Remote protection schemes clear secondary-side faults by creating a bolted primary fault, typically with a grounding switch, or use sacrificial switching or a flash bus. The primary fault is then cleared by line-terminal circuit breakers. The entire transmission line is thus interrupted for both primary- and secondary-side faults sensed by transformer relaying, decreasing service reliability. Faults also take longer to clear, as a result of the sequential operation of two independent systems: the local disconnect switch and the line breakers. Upgrading to a local transformer protective device protects the transformer against the stresses associated with the artificially induced primary-side fault, and will leave the transmission line undisturbed in the event of a secondary-side fault. Much of the relaying and communications used to trigger the protective scheme can be reused with the local protective device.

Selection of a device can also be affected by the bus configuration of the substation. Transformers located on a radial tap off of the transmission line will usually use a single transformer protective device. If there is more than one transformer in the substation, the protective device may be coordinated with a tie switch. When used for transformer protection, circuit breakers or circuit-switchers typically have a minimum of secondary-side overcurrent and sudden pressure relaying. A more critical transformer may have differential relaying and back-up overcurrent relaying, and may also include a neutral overcurrent relay to detect ground faults.

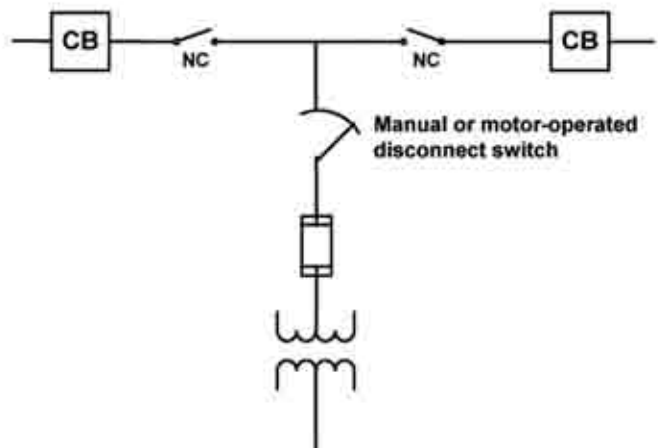
In substations with one or more available sources, the transformer protective device may be coordinated into an automatic switching or “throw-over” scheme. And in urban or dense industrial areas, double-bus or ring-bus arrangements are becoming increasingly more common as the demand for power reliability increases. In these cases, the transformer protective device will have to be rated for both primary and secondary fault interrupting duty as well as for short-line faults — and the associated relay scheme will be quite elaborate.

Explaining the different types of protective relay schemes that can be employed with a primary-side device is outside the scope of this discussion. For a detailed description of the types of relays and relay schemes that can be used with a protective device, refer to ANSI C37.91-1985, “IEEE Guide for Protective Relay Applications to Power Transformers”. [5]

The following is a brief overview of the different local primary-side transformer protective devices available today.

POWER FUSES

Power fuses, shown in Figure 4 in a typical transformer protective application, provide protection that is both reliable and economical. They are inexpensive — both in initial purchased cost and installed cost. When properly applied, their



Power Fuses in Typical Transformer Protective Application
FIGURE 4

characteristics remain unchanged over their operational life. Power fuses are generally applied on transformers rated 10 MVA and smaller.

The operating procedure for power fuses is straightforward.

Typically, after a fuse has operated, the load-side circuit breaker, switch, or recloser is opened. (If no load-side device is in place, the main-secondary circuit breaker or recloser is opened.) Then the line-side series disconnect is opened. Transformer inspection and maintenance can then be performed, and the fuses replaced. To restore service, the line-side series disconnect is closed to pick up transformer magnetizing current. Then the load-side circuit breaker, switch, or recloser is closed.

As mentioned previously, the advantage to using power fuses is their relative low-cost compared to a relayed transformer protective device. Disadvantages include the difficulty in coordinating fuses for secondary-side faults and single-phasing of downstream devices in the event of a single-phase fault. Also, there is no way to implement more advanced relay schemes using differential, neutral overcurrent, or sudden pressure relays. [5]

CIRCUIT-SWITCHER

The author's company developed the first circuit-switcher in 1960 for use in capacitor switching and transformer protection. Early on, it was recognized that the main duty for a circuit-switcher applied for transformer protection would be in clearing secondary faults, so an extensive study of the frequency response of transformers was launched to develop a test method for ensuring that circuit-switchers could clear such faults. The work done at that time is the basis for the present proposed standard. Circuit-switchers use stored-energy operating mechanisms to drive the interrupters open, and have trip-free operating capability. In the event the circuit-switcher is closed into a fault, it will open immediately to interrupt the fault. Many circuit-switcher models are equipped with integral disconnect blades, which provide visual assurance of the device's state and provide working clearance for transformer maintenance or repair.

Shown in Figure 5 is a typical primary-side transformer protection application. Circuit-switchers use the same type of

protective relaying as circuit breakers and both devices provide a similar level of protection. The operating procedure for a circuit-switcher is similar to that of a circuit breaker. After the device has tripped, the circuit-switcher disconnect or separate line-side disconnect is opened (either manually or, in some cases, automatically) to isolate the transformer. Then the load-side series disconnect is opened. Transformer inspection and maintenance can now be performed.

To restore service, the relays are reset, the load-side series disconnect is closed, and the circuit-switcher is then closed.

Circuit-switchers have trip-free operation. So if either the circuit-switcher or the line-side disconnect is closed into a fault, the circuit-switcher will trip to clear the fault.

Unlike circuit breakers, circuit-switchers typically have a short-time current rating higher than their interrupting rating.

The reason for this goes back to the rarity of primary faults and the difficulty in coordinating a transformer protective device with line-terminal circuit breakers, which react to and clear high current faults within 3 cycles. For high current faults, a circuit-switcher typically does not interrupt — either because it is located outside the local zone of protection, or because the

line-terminal circuit breakers operate faster than the typical 5- to 8-cycle operating time of the circuit-switcher.

It is common practice to apply a primary-side protective device that can carry but cannot interrupt the full available high-side fault current on the primary side of the transformer.

Circuit-switchers are available in models from 34.5 kV through 345 kV, with primary-fault interrupting ratings from 8 kA up to 40 kA, secondary-side fault interrupting ratings from 2600 to 4200 amperes, and interrupting times between 3 and 8 cycles.

Faults on the secondary side are low magnitude, so a 3, 6 or 8-cycle operating time will not have much effect on the amount of stress put on the transformer windings. Internal transformer faults are usually detected early in their development by differential or sudden-pressure relays, before much fault current is flowing. And obviously, an internal transformer fault will typically necessitate the removal of the transformer from service and untanking of the transformer for inspection and repair. Generally speaking, a complete rewinding is warranted regardless of whether the fault persisted for 3, 5, 6, or 8 cycles. For these reasons, the fault clearing time of a circuit-switcher isn't as important in selecting a transformer protective device as the

ability to successfully interrupt secondary-side faults.

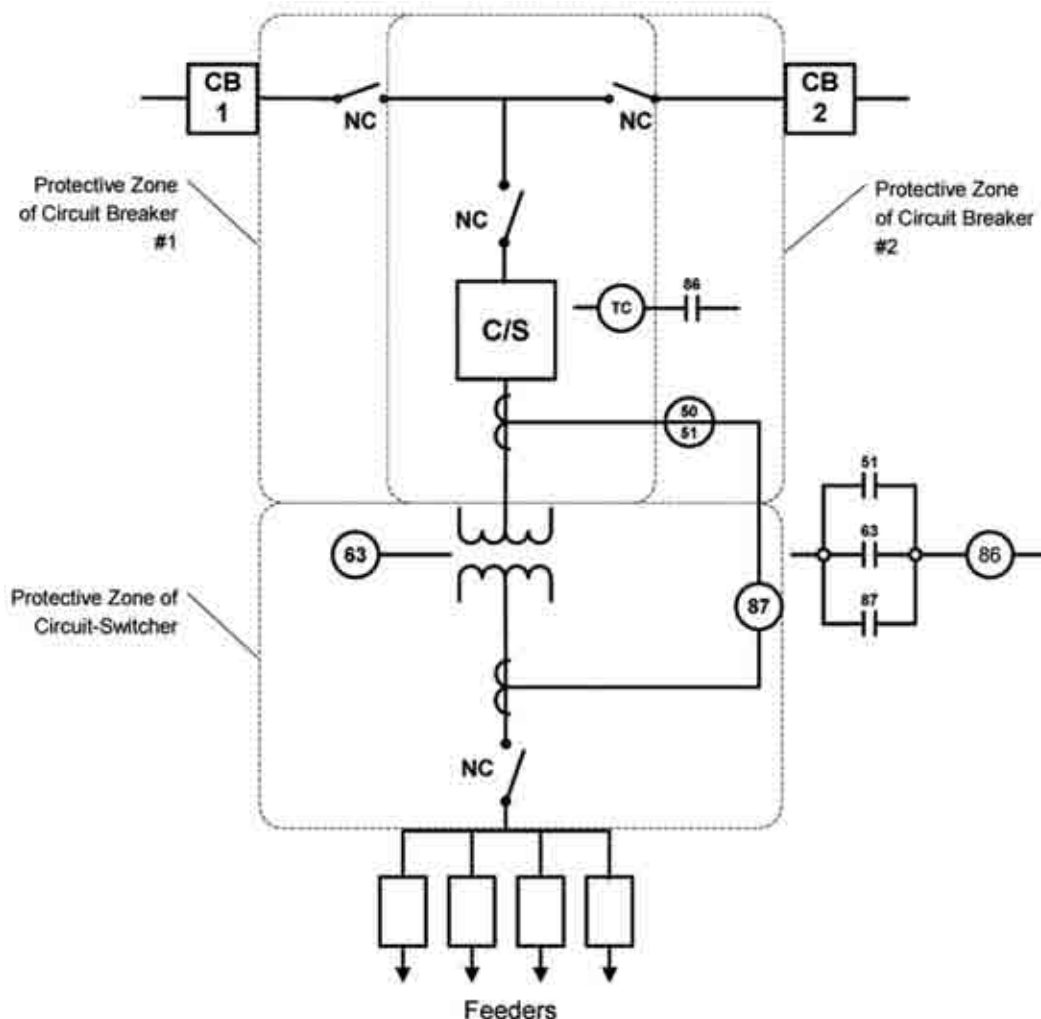
The advantages of circuit-switchers include their ability to provide economical transformer protection, and their ability to be used with a whole range of protective relay schemes.

Many circuit-switchers include integral disconnect blades, which reduce the overall installation time in getting the installation on-line. Disadvantages are that they typically do not have high-speed reclosing or short-line fault capability.

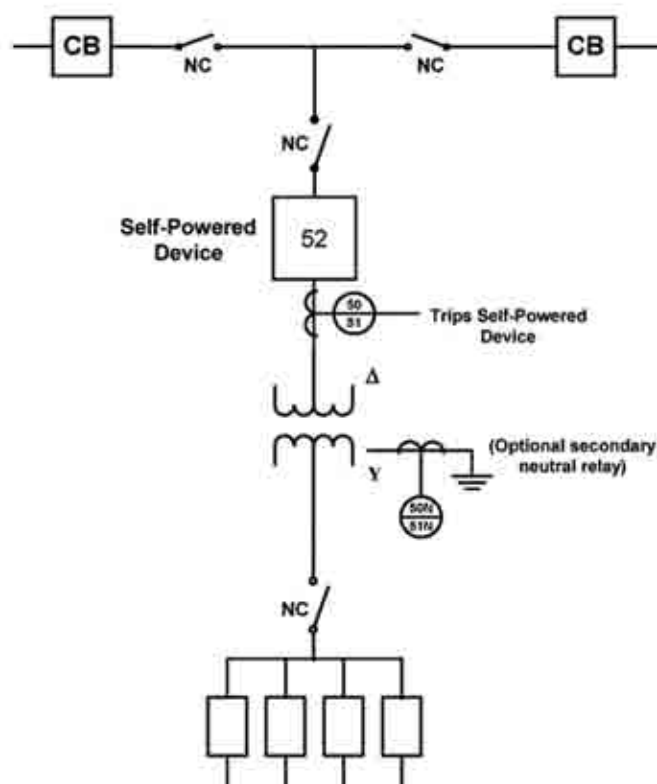
And, due to their live-tank design, the addition of current transformers is quite expensive. This excludes circuit-switchers from use in more complex bus schemes where the transformer protective device also acts as a line protective device.

TRANSFORMER PROTECTIVE DEVICE

The author's company has developed a low-cost power fuse and circuit-switcher replacement which utilizes a modular design. The transformer protective device features puffer-type interrupters similar to that



Circuit-Switcher in Typical Transformer Protective Application
FIGURE 5



Transformer Protector with Overcurrent Protection in Typical Transformer Protective Application
FIGURE 6

used in circuit-switchers.

These interrupters provide a 31.5-kA fault interrupting rating and a 3-cycle interrupting time. Transformer protective devices have been tested for their ability to interrupt fast TRVs and are assigned a secondary-fault interrupting rating similar to circuit-switchers. Each pole-unit is self-contained with its own operating mechanism; the pole-units are filled with SF6 and sealed.

Two versions are available: one which requires an external power source and user-furnished relaying, and one with a self-contained overcurrent protection relay system. The self-powered version is pictured below. (Figure 6.)

The operating procedure for the self-powered version is similar to that of power fuses. After the device has tripped, the load-side circuit breaker, switch, or recloser is opened — either manually or, in some cases, automatically — to isolate the transformer. (If no load-side device is in place, the main secondary circuit breaker or recloser is opened.) Then the line-side series disconnect is opened. Transformer inspection and maintenance can now be performed. To restore service, the pole-units are manually closed and charged for the next opening with a charging tool provided with the device. Each phase is charged separately. Thus, steps for visually verifying the charged status of each phase must be incorporated into the substation operating procedure. After the relay targets have been reset, the line-side series disconnect is closed, picking up transformer magnetizing inrush current. Then the load-side circuit breaker, switch, or recloser is closed. The self-powered version is trip-free; in the rare event that the line-side disconnect is closed into a fault, it will trip to clear the fault.

The transformer protective device was specifically

designed for application on distribution substation transformers. At full load current, it has a continuous current rating of 420 amperes. At 69 kV, it can protect up through a 30/40/50-MVA transformer and it has a 4200-ampere secondary-side fault interrupting rating. At 115 kV, it can protect up through a 37.5/50/62.5-MVA transformer and it has a 2600-ampere secondary-side fault interrupting rating. At the upper extremes of the application range, there are some limitations with respect to the minimum impedance of the transformer, so as to stay within the secondary fault rating of 2600 amperes. [4] [6]

The advantages of transformer protective devices include their ability to provide very economical transformer protection, and their ability to be used with a whole range of protective relay schemes. The compact design and light weight of these devices make them suitable for application where there is little room for a larger protective device. The disadvantage is that some users' operating practices do not allow energizing of a transformer using a disconnect switch — although many users have been doing it for years for fuse applications.

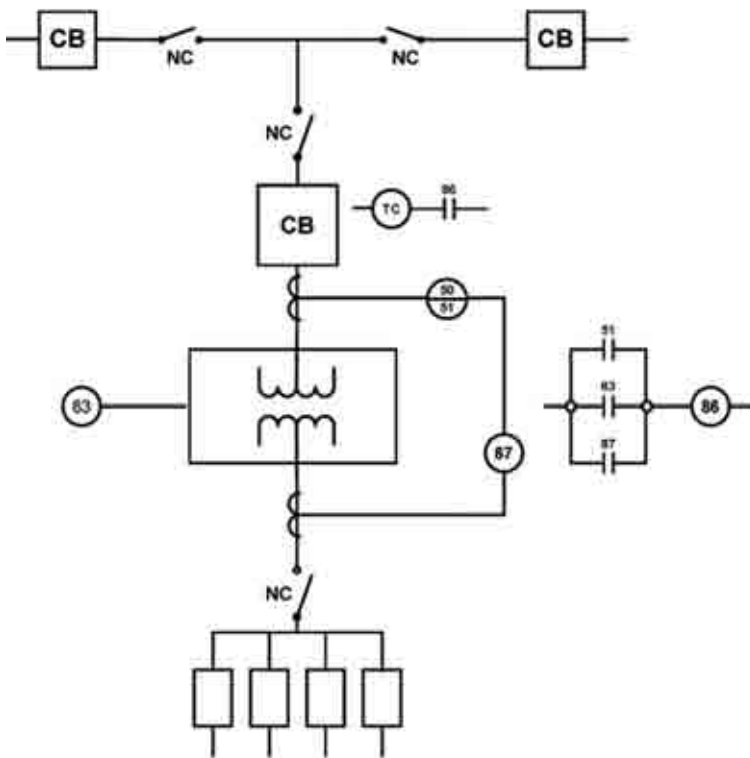
CIRCUIT BREAKER

Circuit breakers are also used for transformer protection, as shown in Figure 7. Like circuit-switchers, circuit breakers are relay-activated. Breakers offer higher interrupting ratings than power fuses and circuit-switchers, are SCADA compatible, and work with the same protective relay schemes as circuit-switchers. Breakers are generally used in complex bus schemes, such as ring-bus or breaker-and-one half schemes. In those situations, the breaker acts as both the transformer protective device and the protective device for the incoming lines — thus the need for high-speed reclosing, short-line fault interrupting capability and, in many cases, high primary-fault current capability. In the United States, dead-tank breakers are typically used since current transformers can be economically applied.

The latest designs of circuit breakers use puffer-type SF6-filled interrupters, as were previously discussed in the section on secondary-side fault interruption. Circuit breakers generally have a stored-energy mechanism that allows the breaker contacts to open and close one or more times after control power has been lost. These mechanisms can be pneumatic or hydraulic, and use compressed air or another compressed gas, or a motor-compressed spring. [3]

For transformer protection, the high-speed reclosing capability of circuit breakers is often undesirable and, in most cases, should be blocked. When the primary-side transformer protection trips in a response to a fault internal to the transformer, it's generally for a good reason. A visit to the substation is usually necessary to determine if the transformer has been damaged. The transformer insulation is tested, and a gas or oil analysis may be performed to check for arc byproducts. In some cases, a turns-ratio test is performed. Since almost no transformer protective scheme uses high-speed reclosing, the feature is unnecessary.

Circuit breakers are "general purpose" switching devices designed for application in a variety of areas on a utility system. Although circuit breakers often have an extremely robust interrupting rating, they are not always tested for their ability to interrupt the fast TRVs associated with secondary side faults. This rating needs to be specified when purchasing a circuit breaker for transformer protection.



Circuit Breaker in Typical Transformer Protective Application
FIGURE 7

CONCLUSION

Providing a local primary-side protective device for each distribution substation transformer affords the best protection against secondary-side faults, and eliminates unnecessary disturbances on the transmission line. When selecting a primary-side protective device, careful examination must be made of its secondary-side fault interrupting capability. Other factors must be taken into consideration, including the cost of the transformer, the criticality of the load, and the available resources.

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- [2] ANSI/IEEE Standard C37.06.1-1997; "Trial Use Guide for High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis Designated "Definite Purpose for Fast Transient Recovery Voltage Rise Times."
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- [6] ANSI/IEEE C57.109-1993; "Guide for Transformer Through-Fault Current Duration."

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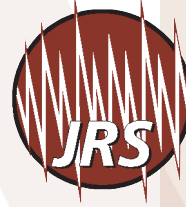
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